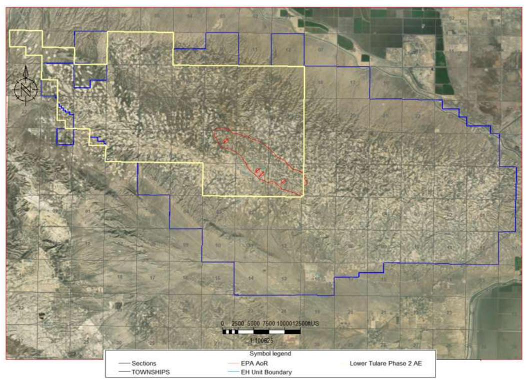
CLASS VI CRITICAL PRESSURE CALCULATION

ELK HILLS 26R PROJECT

<u>Critical Pressure Calculation</u>

As discussed in the Project Narrative document, there is no known USDW with groundwater within the area of review of the project. The Lower Tulare Zone is an exempt aquifer within the project AoR as shown in Figure 1 below.

Figure 1: Lower Tulare aquifer exemption area.

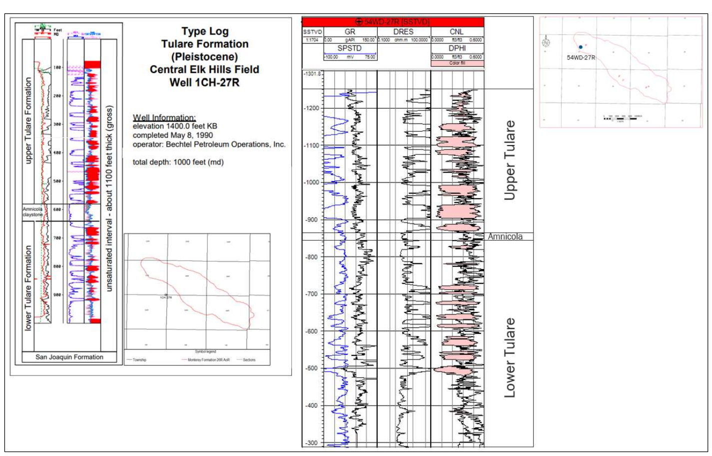


The Upper Tulare zone is characterized as being unsaturated air sands that are dry or at irreducible water saturation in the AoR. For completeness, the Critical pressure calculations for a saturated, normally pressured Upper Tulare zone are discussed below.

Upper Tulare USDW Inputs

The unconfined Upper Tulare Formation within the area of review (AoR) is an open aquifer that onlaps onto the anticline structure. The Upper Tulare within the AoR is an unsaturated zone with no groundwater present. Figure 2 shows the Tulare Formation type wells, note the unsaturated zone by the neutron density cross-over shaded pink and red that is indicative of air sands. For the critical pressure calculation, CTV used the average base of the Upper Tulare within the AoR.

Figure 2: Tulare Formation type wells 1CH-27R and 54WD-27R.



Computational Modeling Monterey Formation A1-A2 Pressure

The Monterey Formation 26R reservoir has been depleted by oil and gas production. Currently the pressure of the reservoir is estimated to be 150 PSI at a datum of 5,630 ft TVD below Mean Sea Level (MSL). The final average reservoir pressure will be at or below the initial reservoir conditions (3,250 PSI).

Critical Pressure Calculation

Using the equation below, and assuming the Upper Tulare has been saturated and is at normal pressure, the critical pressure for the Monterey Formation 26R reservoir is about 2,651 PSI for the project area.

$$P_{\mathrm{i,\,f}} = \frac{\rho_i}{\rho_u} P_{\mathrm{u}} + g\rho_i(Z_i - Z_u)$$

Where,

$P_{i,f}$ – Injection zone Pressure

P_u – Base of USDW zone pressure, (assuming normally pressured, 217 psi or 1,498,686 Pa)

ρi – injection zone brine density, 1017 kg/m3

ρ_u – USDW zone water density, 1003 kg/m3

Zi – Injection zone depth 6014 ft TVD or 1833 m TVD

Zu – Base of USDW zone depth, 502 ft TVD or 153 m TVD

g – acceleration due to gravity, 9.81m/s2

Summary of AoR

The final pressure of the Monterey Formation 26R reservoir will be at or below the initial reservoir pressure to ensure that CO_2 occupies the same pore space that was initially saturated with hydrocarbons and the pressure front is at equilibrium with initial conditions. As such, CTV defines the AoR as the aerial extent of the CO_2 plume.

APPENDIX 2

P&A PROCEDURE FOR WELLS TO BE ABANDONED PRIOR TO INJECTION

CTV will abandon one hundred fifty-seven (157) wells within the AoR prior to injection of CO_2 to isolate the 26R sand from other permeable reservoirs and to ensure confinement through the Reef Ridge upper confining layer. Appendix 1 provides the list of all wells within the AoR and indicates which wells will be abandoned prior to injection. This appendix provides the plugging and abandonment procedures to demonstrate that plugging will ensure isolation of the 26R sand.

Abandonment operations will be conducted using methods designed to prevent the movement of fluid into USDW and will include the use of materials compatible with the carbon dioxide stream. As these are oil and gas wells regulated through CalGEM primacy, procedures and cement plug placement will also adhere to regulations established within the California Code of Regulations, Chapter 4, Article 3, §1723.

Plugging Procedures*

The following procedures describe the proposed plugging operations:

1. Blowout Prevention Equipment (BOPE) is installed on the wellhead.
2. Downhole production or injection equipment is removed from the casing, and the well is cleaned out to Plugback Measured Depth (PBMD) or as deep as possible. The cleanout depth will be witnessed by CalGEM and approved.
3. Plug 1 will be placed from the approved cleanout depth across the production interval and >100’ into the Reef Ridge shale. The plug will be tagged and witnessed by CalGEM to ensure the plug depth and length satisfies permit requirements.
4. Plug 2 will be placed at the top of the Etchegoin formation and >100’ into the San Joaquin formation. The plug will be tagged and witnessed by CalGEM to ensure the plug depth and length satisfies permit requirements.
5. Plug 3 will be placed at the top of the San Joaquin formation. The plug will be extended to cover >100’ above the base of the USDW, if present. The plug will be tagged and witnessed by CalGEM to ensure plug depth and length satisfies permit requirements.
6. Plug 4 will be placed such that the surface plug is >25’ in length, and well casing can be cut off between 5’ and 10’ from surface. The plug will be witnessed at surface by CalGEM to ensure plug depth and length satisfies permit requirements.
7. BOPE will be removed, and well casing will be cut between 5’ and 10’ below surface.
8. A steel plate will be stamped with the last five digits of the API well number for identification. The steel plate will be at least as thick as the outer well casing, and it will be welded around the circumference.

** These procedures are considered standard and are subject to change depending on the wellbore conditions. Any deviation from the permitted procedures affecting abandonment requirements will be conveyed, agreed upon and documented by CalGEM and CRC prior to the change.*

All portions of the well not plugged with cement are filled with inert mud meeting specifications according to California Code of Regulations, Chapter 4, Article 3, §1723(b). to prevent migration of fluids within the wellbore.

Plugging Details for Wells to be Abandoned

Well-specific plugging plans are provided in the following tables for each well to be abandoned prior to CO_2 injection. Cement type, volume, density, and placement method for each plug described above are indicated. The indicated top and bottom plug depths necessary to ensure isolation of 26R Sand and meet CalGEM abandonment requirements are determined based on the well-specific measured depths of the relevant geologic formations described above.

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Appendix: Wellbore Table with Corrective Action Assessment

Well Name	API-12	Well Type	Wellbore Status	Date Drilled	Surface Latitude (°N)	Surface Longitude (°E)	Wellbore Total Measured Depth (ft MD)	Wellbore True Vertical Depth (ft TVD)	[redacted]
312-26R	040292712900	PRODUCER	IDLE	7/9/1951	35.293923	-119.482706	7225	7223	
312-36R	040292726500	ABANDONED	PLUGGED	12/8/1950	35.279644	-119.465089	7016	7016	
312A-36R	040292727900	PRODUCER	ACTIVE	8/14/1953	35.279118	-119.464610	6512	6510	
312H-26R	040300200100	PRODUCER	IDLE	1/12/1994	35.293910	-119.482609	10400	7196	
312H-36R-RD1	040292726501	ABANDONED	PLUGGED	12/8/1950	35.279644	-119.465089	7597	7377	
312H-36R-RD2	040292726502	ABANDONED	PLUGGED	12/8/1950	35.279644	-119.465089	8081	7028	
312H-36R-RD3	040292726503	PRODUCER	ACTIVE	12/8/1950	35.279644	-119.465089	8236	7045	
313-36R	040296322200	PRODUCER	ACTIVE	1/16/1981	35.277065	-119.465130	7500	7493	
313H-26R	040300269900	PRODUCER	ACTIVE	5/26/1994	35.292241	-119.482917	9414	7212	
314-26R	040292713000	PRODUCER	ACTIVE	1/5/1952	35.290252	-119.482576	7316	7316	
314-36R	040292726600	PRODUCER	ACTIVE	1/14/1952	35.276036	-119.464847	7250	7250	
314H-26R	040292715000	ABANDONED	PLUGGED	7/23/1953	35.290542	-119.482555	6770	6769	
314H-26R-RD1	040292715001	PRODUCER	IDLE	7/23/1953	35.290542	-119.482555	9050	7283	
315-26R	040296232000	PRODUCER	ACTIVE	9/20/1980	35.288521	-119.483095	7471	7462	
315-31S	040302970600	PRODUCER	IDLE	4/9/2006	35.275671	-119.446069	6887	5830	
315X-31S	040300341200	PRODUCER	ACTIVE	3/15/1995	35.274716	-119.446364	7469	7429	
316-26R	040292713100	INJECTOR	ACTIVE	4/12/1952	35.286646	-119.482572	7435	7435	
316A-31S	040298934700	PRODUCER	ACTIVE	8/2/1991	35.272916	-119.445715	7550	7396	
316H-31S	040302827400	PRODUCER	ACTIVE	9/12/2005	35.272822	-119.446825	7240	5451	
316H-36R	040298480000	PRODUCER	ACTIVE	8/26/1989	35.272280	-119.465497	9054	7288	
316X-31S	040303537800	INJECTOR	ACTIVE	6/12/2008	35.274205	-119.445713	6711	6673	
317-25R	040292710600	INJECTOR	IDLE	5/26/1950	35.285014	-119.464571	7400	7359	
317-26R-RD1	040295169801	PRODUCER	ACTIVE	8/5/1975	35.284832	-119.482546	7600	7439	
317X-25R	040302987600	PRODUCER	ACTIVE	4/24/2006	35.284867	-119.465815	6495	6476	
318-25R	040297068200	ABANDONED	PLUGGED	2/20/1984	35.283417	-119.464982	8000	8000	
318H-25R-RD1	040297068201	ABANDONED	PLUGGED	2/20/1984	35.283417	-119.464982	7953	7453	
318H-25R-RD2	040297068202	ABANDONED	PLUGGED	2/20/1984	35.283417	-119.464982	8011	7484	
318H-25R-RD3	040297068203	ABANDONED	PLUGGED	2/20/1984	35.283417	-119.464982	7816	7491	
318H-25R-RD4	040297068204	PRODUCER	IDLE	2/20/1984	35.283417	-119.464982	8657	7106	
321H-36R	040300275400	PRODUCER	ACTIVE	8/3/1994	35.280661	-119.462699	9365	9259	
321X-36R	040297563800	PRODUCER	IDLE	8/4/1985	35.280625	-119.462900	7800	7760	
322-36R	040292726700	PRODUCER	ACTIVE	2/1/1950	35.279515	-119.462927	7150	7150	
322A-26R	040296828900	ABANDONED	PLUGGED	2/1/1983	35.293756	-119.480816	7525	7525	
322A-26R-RD1	040296828901	INJECTOR	IDLE	2/1/1983	35.293756	-119.480816	7325	7185	
322A-35R	040296819300	INJECTOR	ACTIVE	1/11/1983	35.279826	-119.480754	7761	7527	
322A-36R	040296183500	PRODUCER	IDLE	6/22/1980	35.279284	-119.462749	6400	6338	
323-36R	040296061900	PRODUCER	ACTIVE	1/19/1980	35.277266	-119.462398	7600	7593	
324-36R	040296827600	PRODUCER	ACTIVE	2/5/1983	35.275799	-119.463228	7600	7571	
324H-35R	040302366600	ABANDONED	PLUGGED	12/4/2003	35.276056	-119.479074	7635	7349	
324H-35R-RD1	040302366601	PRODUCER	IDLE	12/4/2003	35.276056	-119.479074	10440	7130	
325-26R	040295215800	PRODUCER	ACTIVE	10/28/1975	35.288448	-119.480393	7493	7487	
326-26R	040296238100	PRODUCER	ACTIVE	10/25/1980	35.286777	-119.480537	7500	7490	
326X-25R	040302936600	PRODUCER	ACTIVE	4/2/2006	35.287055	-119.462412	7428	5797	
327-25R	040292711000	PRODUCER	ACTIVE	4/14/1949	35.284826	-119.462911	7050	7048	
328-25R	040295904300	PRODUCER	IDLE	3/15/1979	35.283193	-119.462590	6675	6668	
331X-36R	040296858000	PRODUCER	ACTIVE	4/12/1983	35.281354	-119.461505	7050	7003	
3-32A-36R	040295867400	PRODUCER	ACTIVE	12/19/1978	35.279498	-119.461392	8027	7714	
332X-26R	040303388100	PRODUCER	ACTIVE	8/19/2007	35.292532	-119.478358	7523	7125	
332XL-36R	040297558900	PRODUCER	ACTIVE	6/22/1985	35.279291	-119.462092	7800	7701	
333-26R	040305130000	PRODUCER	ACTIVE	3/30/2014	35.294928	-119.476848	6884	6835	
333X-26R	040296859300	PRODUCER	IDLE	4/11/1983	35.291891	-119.477787	7266	7211	
334-26R	040292713300	PRODUCER	IDLE	6/7/1951	35.290279	-119.478147	6242	6242	
334-36R	040292726800	PRODUCER	ACTIVE	12/8/1952	35.275888	-119.459914	7422	7401	
334A-26R	040292715100	PRODUCER	ACTIVE	9/12/1953	35.290057	-119.477918	6960	6960	
334A-36R	040292728000	OBSERVATION	ACTIVE	8/10/1953	35.275784	-119.459503	6620	6620	
334H-26R	040300545300	PRODUCER	ACTIVE	4/3/1996	35.289658	-119.477459	9895	7290	
334XA-26R	040303388200	PRODUCER	ACTIVE	9/4/2007	35.290242	-119.477804	7630	7153	
334XH-26R	040296871600	ABANDONED	PLUGGED	5/15/1983	35.290722	-119.477873	7750	7750	
334XH-26R-RD1	040296871601	ABANDONED	PLUGGED	5/15/1983	35.290722	-119.477873	7918	7392	
334XH-26R-RD2	040296871602	ABANDONED	PLUGGED	5/15/1983	35.290722	-119.477873	8232	7454	
334XH-26R-RD3	040296871603	PRODUCER	ACTIVE	5/15/1983	35.290722	-119.477873	9100	7188	
336-26R	040292713400	ABANDONED	PLUGGED	10/15/1951	35.286642	-119.478339	7533	7533	
336-36R	040292726900	ABANDONED	PLUGGED	6/20/1953	35.272529	-119.460049	7498	7494	
336-36R-RD1	040292726901	PRODUCER	IDLE	6/20/1953	35.272529	-119.460049	8050	7598	
336A-26R	040292715200	ABANDONED	PLUGGED	6/7/1953	35.286931	-119.478288	6600	6596	
336A-26R-RD1	040292715201	OBSERVATION	ACTIVE	6/7/1953	35.286931	-119.478288	6575	6575	
336H-26R-RD1	040292713401	ABANDONED	PLUGGED	10/15/1951	35.286642	-119.478339	7541	7414	
336H-26R-RD2	040292713402	ABANDONED	PLUGGED	10/15/1951	35.286642	-119.478339	7621	7502	
336H-26R-RD3	040292713403	PRODUCER	IDLE	10/15/1951	35.286642	-119.478339	7827	7156	
337-26R	040296351000	PRODUCER	ACTIVE	3/7/1981	35.284834	-119.477875	7450	7436	
337H-31S-RD2	040298546302	PRODUCER	IDLE	2/19/1990	35.270030	-119.441802	7068	5734	
337X-25R	040302844100	PRODUCER	ACTIVE	3/27/2006	35.285452	-119.460784	6612	5689	

Well Name	API-12	Well Type	Wellbore Status	Date Drilled	Surface Latitude (°N)	Surface Longitude (°E)	Wellbore Total Measured Depth (ft MD)	Wellbore True Vertical Depth (ft TVD)
338-22R-RD1	040295104001	INJECTOR	IDLE	5/21/1975	35.297380	-119.496225	7400	7280
338-25R	040292711300	PRODUCER	ACTIVE	7/1/1951	35.282836	-119.460228	7400	7268
338-26R	040292713500	PRODUCER	IDLE	5/2/1953	35.283026	-119.478117	7400	7400
341-27R	040295037600	INJECTOR	ACTIVE	2/7/1975	35.295378	-119.493594	9885	9867
341-35R	040295168600	PRODUCER	IDLE	9/9/1975	35.281200	-119.475900	7498	7498
341-36R	040292727000	PRODUCER	ACTIVE	12/11/1950	35.281287	-119.458331	7130	7130
341A-35R	040296730600	PRODUCER	IDLE	8/5/1982	35.281432	-119.475515	7600	7528
342X-36R	040298627900	PRODUCER	ACTIVE	6/10/1990	35.277599	-119.457910	8135	8081
343-27R	040295103600	ABANDONED	PLUGGED	6/25/1975	35.292027	-119.493574	7800	7789
343-27R-RD1	040295103601	PRODUCER	IDLE	6/25/1975	35.292027	-119.493574	7476	7328
343H-36R	040300582500	PRODUCER	ACTIVE	5/15/1996	35.277431	-119.456537	9867	7364
343X-26R	040301396400	PRODUCER	ACTIVE	9/13/1999	35.293036	-119.475316	6895	6888
343X-36R	040298145500	PRODUCER	ACTIVE	10/11/1987	35.277110	-119.456511	8115	8037
344-26R	040292713600	INJECTOR	ACTIVE	11/11/1951	35.290381	-119.476051	7285	7285
344-36R	040292727100	PRODUCER	IDLE	12/27/1950	35.276069	-119.458128	7315	7315
344H-36R	040302851900	PRODUCER	IDLE	12/1/2005	35.276495	-119.457680	8120	6072
345-36R	040296095400	PRODUCER	IDLE	2/21/1980	35.274342	-119.457770	7900	7889
345H-26R	040300213700	PRODUCER	IDLE	3/2/1994	35.287446	-119.476145	9728	7277
346H-26R	040301570400	ABANDONED	PLUGGED	6/30/2000	35.285980	-119.475342	6315	6306
346H-26R-RD1	040301570401	PRODUCER	ACTIVE	6/30/2000	35.285980	-119.475342	7998	7254
347-26R	040295298100	PRODUCER	ACTIVE	9/3/1976	35.284838	-119.475918	8200	8179
347H-31S-RD2	040292749702	PRODUCER	IDLE	12/7/1950	35.270836	-119.439080	8200	5934
348-25R	040292711400	PRODUCER	ACTIVE	11/22/1950	35.283195	-119.458264	5839	5839
348-26R	040296273200	PRODUCER	ACTIVE	12/4/1980	35.282702	-119.476449	8200	8191
348X-25R	040303258300	PRODUCER	ACTIVE	3/18/2007	35.283738	-119.457629	7113	5591
351-27R	040296410200	PRODUCER	IDLE	5/3/1981	35.295571	-119.491966	7450	7434
351A-36R	040303419000	PRODUCER	ACTIVE	11/18/2007	35.281351	-119.454670	5920	5668
351X-36R	040302643500	ABANDONED	PLUGGED	2/17/2005	35.281140	-119.456566	4694	4690
351X-36R-RD1	040302643501	PRODUCER	IDLE	2/17/2005	35.281140	-119.456566	5965	5928
352-27R	040292715900	PRODUCER	IDLE	3/24/1953	35.293858	-119.491234	7423	7423
352-35R	040292725500	PRODUCER	IDLE	9/17/1952	35.279358	-119.473735	7457	7457
352-36R	040292727200	PRODUCER	ACTIVE	9/10/1952	35.279108	-119.455146	6625	6625
352X-36R	040303221100	PRODUCER	ACTIVE	3/7/2007	35.278734	-119.455416	6911	6637
353-26R	040298107600	PRODUCER	ACTIVE	10/9/1987	35.292051	-119.473922	7425	7327
353X-35R	040296736500	INJECTOR	ACTIVE	8/31/1982	35.276718	-119.473279	7756	7512
354-26R	040301402000	PRODUCER	ACTIVE	10/24/1999	35.290626	-119.473639	6927	6916
354H-35R	040298860600	ABANDONED	PLUGGED	5/12/1991	35.275035	-119.473363	8545	8532
354H-35R-RD4	040298860604	INJECTOR	IDLE	5/12/1991	35.275035	-119.473363	9485	7289
354H-36R	040295827200	ABANDONED	PLUGGED	10/24/1978	35.275720	-119.454697	8136	8136
354H-36R-RD1	040295827201	ABANDONED	PLUGGED	10/24/1978	35.275720	-119.454697	6373	6223
354H-36R-RD2	040295827202	PRODUCER	IDLE	10/24/1978	35.275720	-119.454697	7155	5970
355-26R	040295985300	PRODUCER	ACTIVE	9/22/1975	35.288450	-119.473751	6025	6024
355A-26R	040297201900	INJECTOR	ACTIVE	8/12/1984	35.288108	-119.473383	7275	7251
355X-26R	040303395700	PRODUCER	ACTIVE	9/25/2007	35.289274	-119.471788	7106	6552
355X-36R	040296679500	ABANDONED	PLUGGED	3/28/1982	35.274544	-119.453739	6486	6468
355X-36R-RD1	040296679501	INJECTOR	ACTIVE	3/28/1982	35.274544	-119.453739	7865	7763
356-26R	040292713800	PRODUCER	IDLE	12/31/1950	35.286794	-119.473641	6138	6138
356-36R	040292727300	PRODUCER	ACTIVE	12/20/1953	35.272182	-119.455265	7350	7350
356A-26R	040292715400	PRODUCER	ACTIVE	9/7/1953	35.286996	-119.473983	6740	6740
356X-26R	040297857900	ABANDONED	PLUGGED	9/30/1986	35.287327	-119.474394	7800	7761
356XH-26R-RD1	040297857901	ABANDONED	PLUGGED	9/30/1986	35.287327	-119.474394	7740	1869
356XH-26R-RD2	040297857902	PRODUCER	ACTIVE	9/30/1986	35.287327	-119.474394	8390	663
358-26R	040292713900	PRODUCER	ACTIVE	3/13/1951	35.283015	-119.473751	6644	6644
358-26R-RD1	040292713901	ABANDONED	PLUGGED	3/13/1951	35.283015	-119.473751	6950	6878
358-26R-RD2	040292713902	ABANDONED	PLUGGED	3/13/1951	35.283015	-119.473751	7016	6931
358A-26R	040292715500	PRODUCER	ACTIVE	8/12/1953	35.283251	-119.474033	7330	7328
361-27R	040295168400	INJECTOR	ACTIVE	10/18/1975	35.295679	-119.489236	7475	7472
361-35R	040295298200	PRODUCER	ACTIVE	5/23/1976	35.281154	-119.471737	7500	7485
3-62-36R	040292727400	PRODUCER	ACTIVE	4/7/1950	35.279515	-119.453444	5874	5874
362H-36R	040302850200	PRODUCER	ACTIVE	12/30/2005	35.279433	-119.451824	7252	5070
362X-36R	040302769300	PRODUCER	IDLE	8/26/2005	35.280163	-119.454189	7369	6957
363-26R	040292714100	PRODUCER	ACTIVE	9/12/1949	35.291850	-119.471579	7060	7060
363-27R	040296444100	INJECTOR	ACTIVE	5/6/1981	35.292157	-119.489427	7500	7409
363-36R	040292727500	PRODUCER	IDLE	11/20/1949	35.277867	-119.453429	7268	7268
363X-26R	040303510100	INJECTOR	ACTIVE	5/21/2008	35.292321	-119.472194	6645	6627
364-26R	040295924800	PRODUCER	ACTIVE	4/21/1979	35.289529	-119.471742	6760	6752
364X-26R	040303234300	PRODUCER	IDLE	2/21/2007	35.289402	-119.471397	6464	6063
365-36R	040295292800	PRODUCER	ACTIVE	4/10/1976	35.274048	-119.452423	7700	7687
365AH-36R	040301681900	PRODUCER	IDLE	10/7/2000	35.274207	-119.452176	8015	6143
365H-35R-RD1	040298992601	PRODUCER	IDLE	3/6/1992	35.273621	-119.470527	9315	5780
366-26R	040292714200	PRODUCER	IDLE	12/11/1949	35.286636	-119.471540	6912	6912
366A-26R	040296857800	PRODUCER	IDLE	3/28/1983	35.286131	-119.471437	7300	7241
366H-26R	040300289200	PRODUCER	ACTIVE	9/21/1994	35.286006	-119.472708	10165	7305
366X-36R	040296726800	INJECTOR	IDLE	10/10/1982	35.272699	-119.451637	7929	7864
367-26R	040297046500	INJECTOR	IDLE	1/23/1984	35.285522	-119.471121	7700	7653
367-36R	040295955000	PRODUCER	ACTIVE	8/29/1979	35.270201	-119.454206	7500	7483
368H-26R	040301603400	PRODUCER	ACTIVE	7/7/2000	35.283264	-119.471932	7550	7126
371-35R	040296410000	PRODUCER	ACTIVE	4/15/1981	35.280826	-119.468890	7500	7475

[redacted]

Well Name	API-12	Well Type	Wellbore Status	Date Drilled	Surface Latitude (°N)	Surface Longitude (°E)	Wellbore Total Measured Depth (ft MD)	Wellbore True Vertical Depth (ft TVD)
372-27R	040292716000	PRODUCER	IDLE	2/24/1952	35.293873	-119.487012	7283	7283
372-35R	040292725600	ABANDONED	PLUGGED	8/20/1951	35.279373	-119.469313	7171	7145
372H-35R-RD1	040292725601	PRODUCER	IDLE	8/20/1951	35.279373	-119.469313	8310	7304
372X-36R	040300237000	PRODUCER	IDLE	2/2/1994	35.278998	-119.450051	7480	7380
373-26R	040302474000	PRODUCER	ACTIVE	5/19/2004	35.290307	-119.469586	6235	6145
373-35R	040296802800	INJECTOR	ACTIVE	12/14/1982	35.276257	-119.473385	8001	7640
374-27R	040292716100	INJECTOR	ACTIVE	10/28/1952	35.290233	-119.487181	7432	7430
374-36R	040292727600	PRODUCER	IDLE	7/14/1952	35.275743	-119.450402	7200	7200
375-26R	040296028500	PRODUCER	IDLE	11/27/1979	35.288413	-119.469481	7300	7281
375-36R	040302617400	PRODUCER	IDLE	12/1/2004	35.274038	-119.450084	6515	6478
375X-26R	040303868000	PRODUCER	ACTIVE	5/1/2010	35.288156	-119.469048	7734	7356
376-36R	040295585300	INJECTOR	ACTIVE	7/23/1977	35.271778	-119.450192	8500	8327
376XH-36R	040300630800	ABANDONED	PLUGGED	9/7/1996	35.271442	-119.449553	6882	6466
376XH-36R-RD1	040300630800	PRODUCER	IDLE	9/7/1996	35.271442	-119.449553	6882	6466
377-26R	040295872100	PRODUCER	ACTIVE	2/14/1979	35.284827	-119.469329	7411	7404
377-36R	040297616000	PRODUCER	IDLE	9/12/1985	35.270178	-119.450452	7550	7455
377H-26R	040300461900	PRODUCER	ACTIVE	12/13/1995	35.284036	-119.469932	10630	7328
377XH-36R	040302086100	PRODUCER	IDLE	8/1/2002	35.270710	-119.451165	8084	6215
378-26R	040292714400	PRODUCER	ACTIVE	5/25/1951	35.283415	-119.469241	8650	8650
378A-26R	040292715600	INJECTOR	ACTIVE	4/15/1952	35.283414	-119.468902	7010	7009
378H-26R	040300262500	PRODUCER	ACTIVE	4/12/1994	35.283414	-119.469579	9740	9725
378X-26R-RD1	040297199201	ABANDONED	PLUGGED	5/23/1984	35.283558	-119.468784	7800	7722
381-35R	040295232700	PRODUCER	ACTIVE	11/20/1975	35.281198	-119.467616	8635	8610
381H-27R	040300343900	PRODUCER	IDLE	7/2/1995	35.295995	-119.485579	10449	7283
382AH-27R	040300366200	PRODUCER	IDLE	11/8/1995	35.293949	-119.483692	9842	7262
382H-27R	040300052600	PRODUCER	IDLE	4/7/1993	35.293613	-119.483786	9524	7241
383-27R	040295232600	PRODUCER	IDLE	12/9/1975	35.292070	-119.484794	7500	7499
383-35R	040295279200	ABANDONED	PLUGGED	3/4/1976	35.277209	-119.466651	7500	7492
383-35R-RD1	040295279201	PRODUCER	ACTIVE	3/4/1976	35.277209	-119.466651	7450	7444
383-36R	040303109800	PRODUCER	ACTIVE	9/16/2006	35.277676	-119.447746	7065	7035
383H-34R	040302400300	PRODUCER	IDLE	1/29/2004	35.278287	-119.484422	10534	7035
384-27R	040296378100	PRODUCER	IDLE	4/9/1981	35.289841	-119.484848	7450	7436
384-36R	040292727800	ABANDONED	PLUGGED	9/27/1950	35.275760	-119.448007	6150	6150
384-36R-RD1	040292727801	PRODUCER	IDLE	9/27/1950	35.275760	-119.448007	6645	6631
384A-36R	040295992800	PRODUCER	ACTIVE	9/28/1979	35.276035	-119.448518	7100	7092
385-27R	040295168500	PRODUCER	IDLE	9/28/1975	35.288454	-119.484776	7500	7493
386-26R	040292714800	PRODUCER	IDLE	10/1/1948	35.286636	-119.467117	7213	7207
386-36R	040297275600	PRODUCER	ACTIVE	9/26/1984	35.272625	-119.447359	7200	7136
386A-26R	040295923900	PRODUCER	IDLE	5/22/1979	35.286159	-119.467051	6650	6644
387-36R	040296709600	INJECTOR	IDLE	7/28/1982	35.271327	-119.448381	8100	8027
3-88AH-26R	040300717200	PRODUCER	ACTIVE	12/7/1996	35.283065	-119.467773	10727	7339
388H-26R	040300343800	PRODUCER	ACTIVE	8/16/1995	35.283390	-119.467223	9800	7337
388U-26R	040292714900	PRODUCER	ACTIVE	10/23/1950	35.283115	-119.467221	7405	7402
4-322-26R	040292713200	PRODUCER	ACTIVE	11/27/1949	35.293839	-119.480308	7046	7044
4-322H-35R	040300052700	PRODUCER	IDLE	2/12/1993	35.279967	-119.480656	9752	9714
4-325-36R	040296097800	PRODUCER	ACTIVE	5/12/1980	35.274084	-119.462885	7600	7588
4-332H-36R	040300450900	PRODUCER	IDLE	9/27/1995	35.278811	-119.460924	9712	7335
4-338A-26R	040292715300	PRODUCER	IDLE	2/9/1954	35.283444	-119.478553	7024	7024
4-338H-36R	040298996000	PRODUCER	ACTIVE	5/14/1992	35.269183	-119.460435	9580	7056
4-344A-26R	040296857700	PRODUCER	ACTIVE	5/12/1983	35.289578	-119.475654	8025	7953
4-364-27R	040296832200	PRODUCER	IDLE	3/1/1983	35.290236	-119.489205	7500	7485
4-374-26R	040292714300	PRODUCER	ACTIVE	5/21/1951	35.290127	-119.469223	5570	5570
4-378X-26R	040297199200	ABANDONED	PLUGGED	5/23/1984	35.283558	-119.468784	6694	6669
4-378X-26R-RD2	040297199202	PRODUCER	IDLE	5/23/1984	35.283558	-119.468784	7734	7692

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ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

Elk Hills 26R Storage Project

Version History

File Name	Version	Date	Description of Change
Attachment A - Narrative	1	01/11/21	Original version was submitted as Attachment A - Narrative
Attachment A Site Characterization	2	05/31/22	Site Characterization Evaluation

Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate four CO_2 geologic sequestration wells at the Elk Hills Oil Field (EHOF) 26R reservoir located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential CO_2 stored in the 26R Monterey Formation reservoir up to 1.46 million tonnes annually for 26 years with injection starting in 2025. The anthropogenic CO_2 will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. The project will consist of four injectors, surface facilities, and monitoring wells. This supporting documentation applies to the four injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

Class VI - Wells used for Geologic Sequestration of CO_2

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Site Characterization

Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

Elk Hills Field History

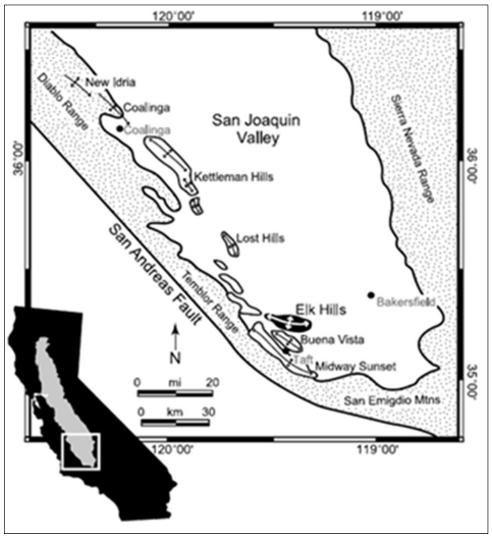
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation 26R sequestration reservoir was discovered in the 1940's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

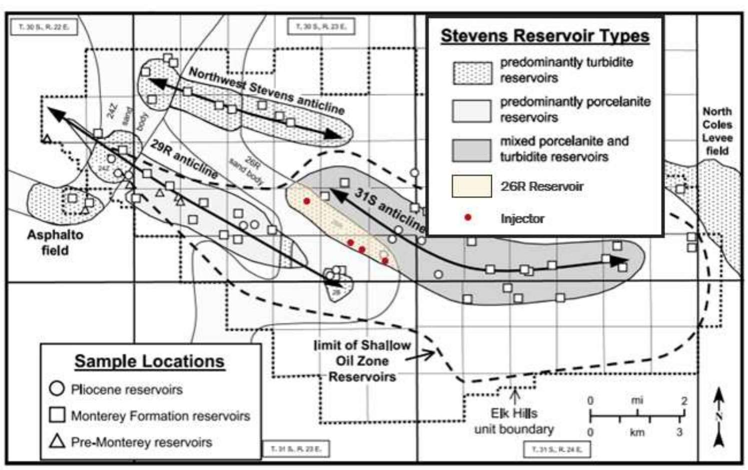
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.



The EHOF has three anticlines Northwest Stevens, 31S and 29R that (Figure 2) are separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

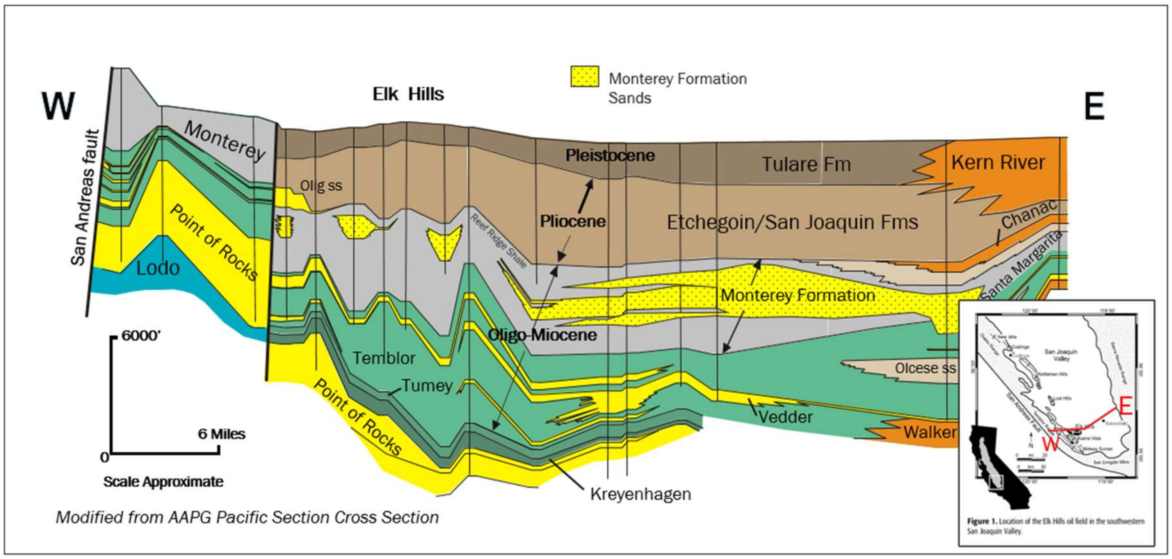
Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation 26R CO_2 sequestration reservoir is located in the 31S anticline (Zumberge, 2005). Sample locations for oil geochemistry are shown.



Geological Sequence

Figure 3 shows the stratigraphy of the EHOF. The Miocene aged Monterey Formation 26R reservoir at the 31S anticline is approximately6,000 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by over 40 years of oil and gas production and injection history.

Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).



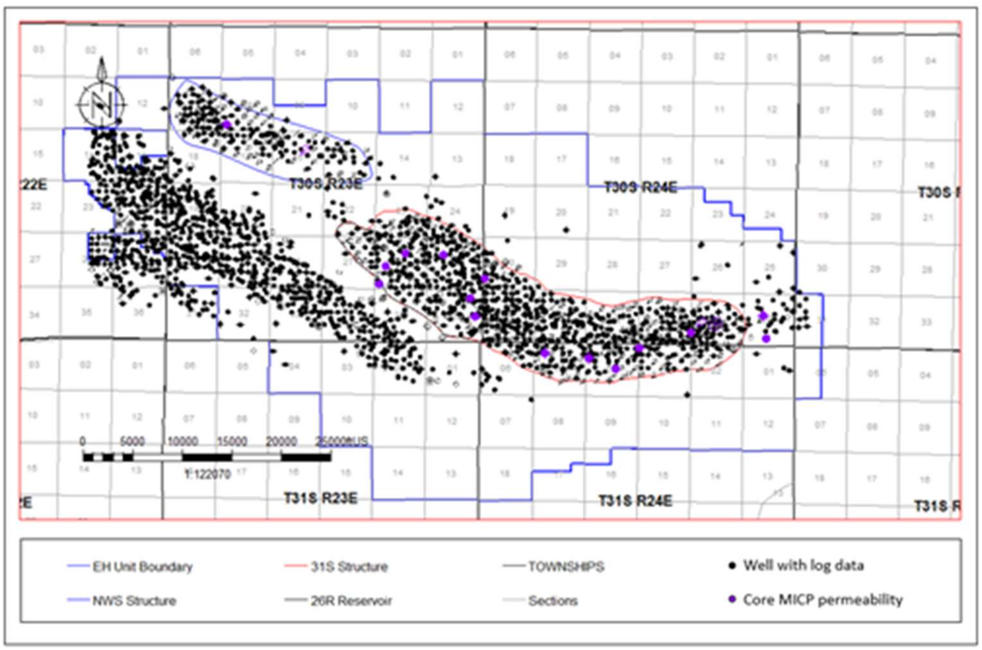
Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin and serves as the primary confining layer for the Monterey Formation 26R reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 4), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

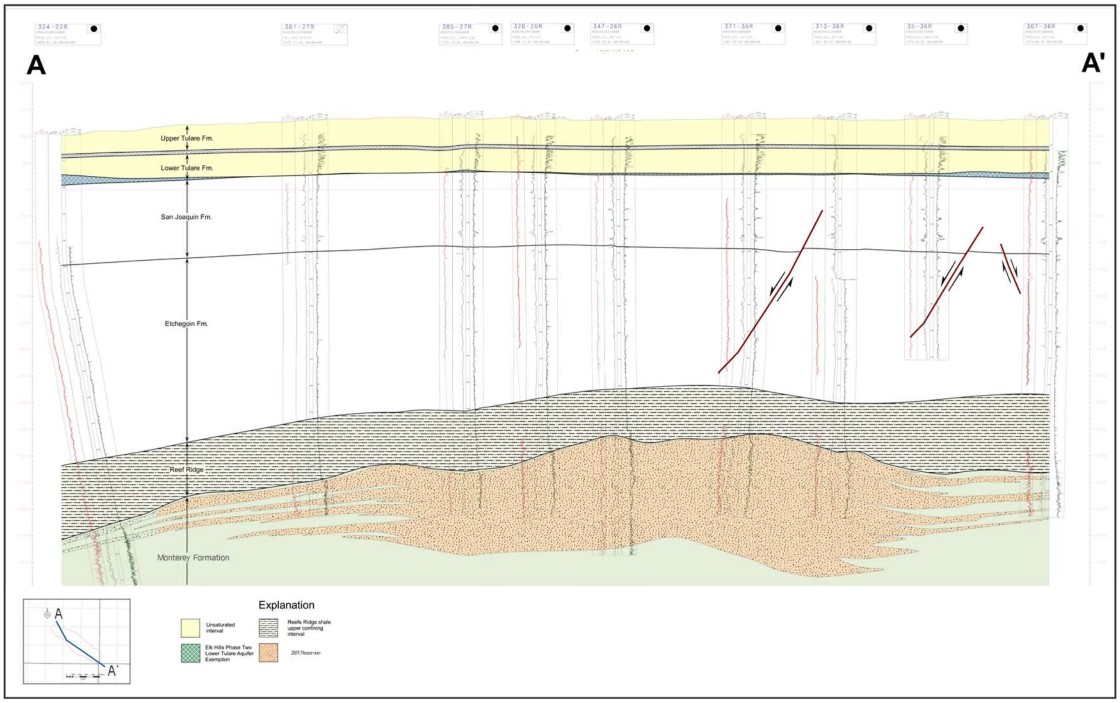
Figure 4: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs that define structure and lithology of the storage reservoir and Reef Ridge confining layer. Wells with MICP core from the Monterey Formation are shown in purple.



Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation, Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 5 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

Figure 5: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the 31S anticline.



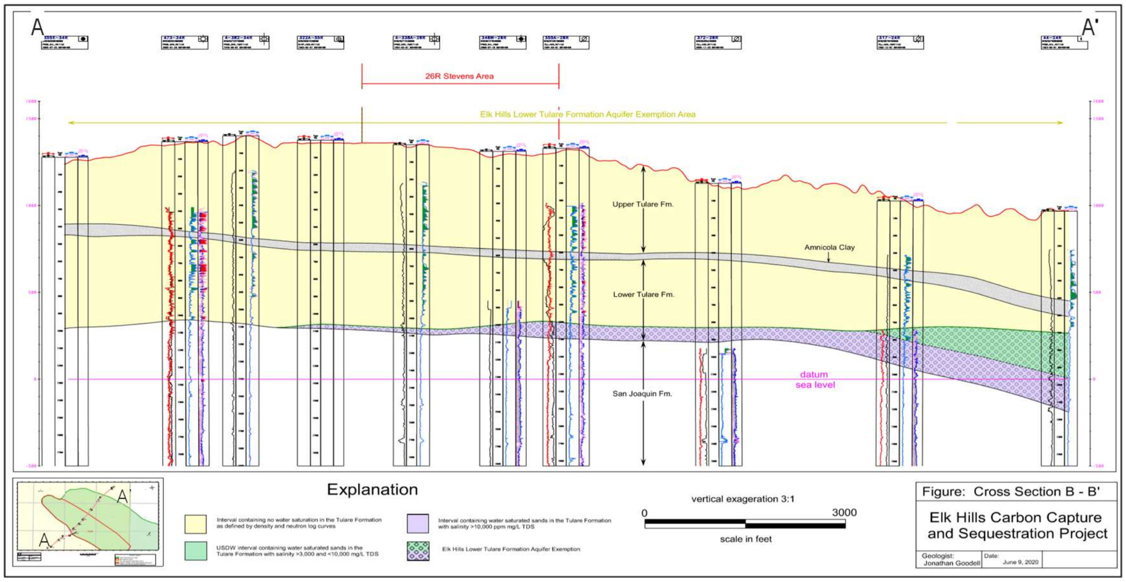
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 6), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare is an unsaturated air sand above the Monterey Formation 26R reservoir. The Lower Tulare formation was approved as an exempt aquifer in 2018.

Figure 6: The Tulare Formation consists of the Upper Tulare and Lower Tulare separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer and the Upper Tulare is an unsaturated air sand.



San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds (Maher et al., 1975). The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible CO_2 leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000' in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

The Etchegoin Formation will dissipate CO2 and CTV will drill and equip a monitoring well to assess formation pressure and water quality changes during the project.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 5,000 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

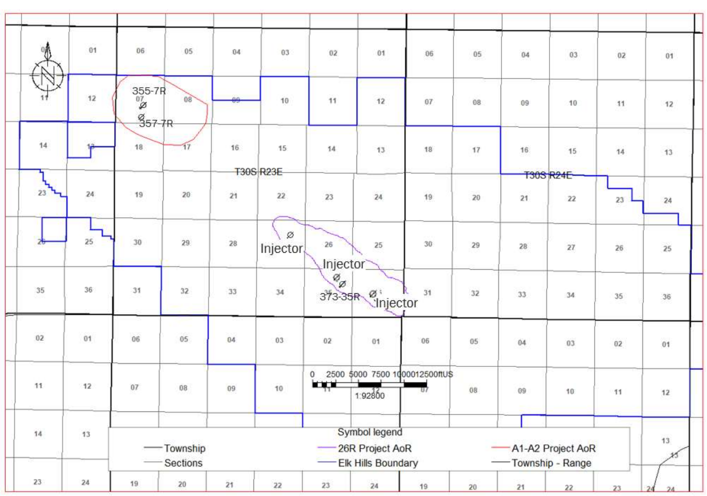
The Reef Ridge directly overlies the 26R Monterey Formation sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

Monterey Formation

The 26R Monterey Formation sequestration reservoir is approximately 6,000 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 25% and 45 mD, respectively.

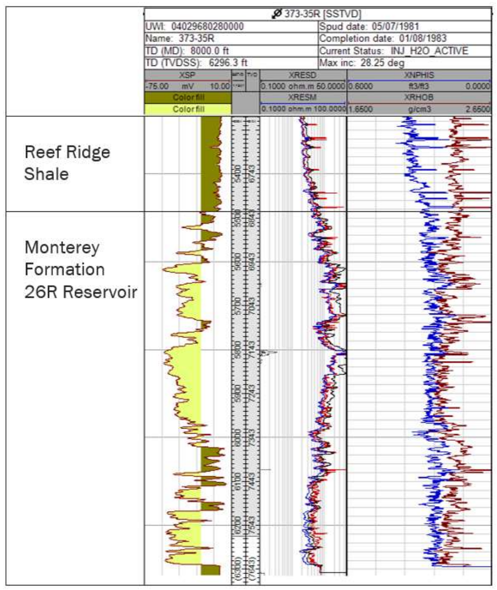
The 26R Monterey Formation sands were deposited as a turbidite channel influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. The turbidite sands were largely aggregational with minimal erosive deposition.

Figure 7: AoR and injection well location map for the Elk Hills 26R project and Elk Hills A1-A2 project. Well location shown is defined by the well path intersection with the Monterey Formation.



The reservoir is continuous across the AoR and the sands pinch-out up-dip and on the channel edges (Figure 5). As such, the 26R Monterey Formation sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

Figure 8: 373-35R injector showing the Monterey Formation 26R reservoir.



Summary:

The Monterey Formation 26R project will be developed with four injectors (Figure 7), three wells to be drilled prior to the initiation of injection and the existing 373-35R well (Figure 8).

The storage reservoir depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as vertical confinement by the Reef Ridge Shale and lateral reservoir confinement.

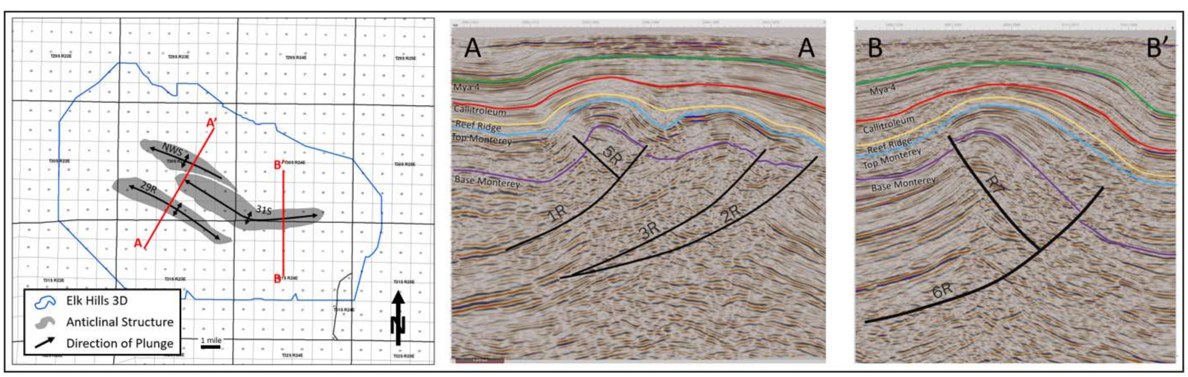
Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the 31S anticline are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale in the Monterey Formation 26R reservoir. CTV reviewed the seismic in the AoR and assessed all the major reflectors. There were no reflectors showing offset of the Monterey Formation nor Reef Ridge in the AoR that would indicate faulting.

Figure 9: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.



Fluid Confinement

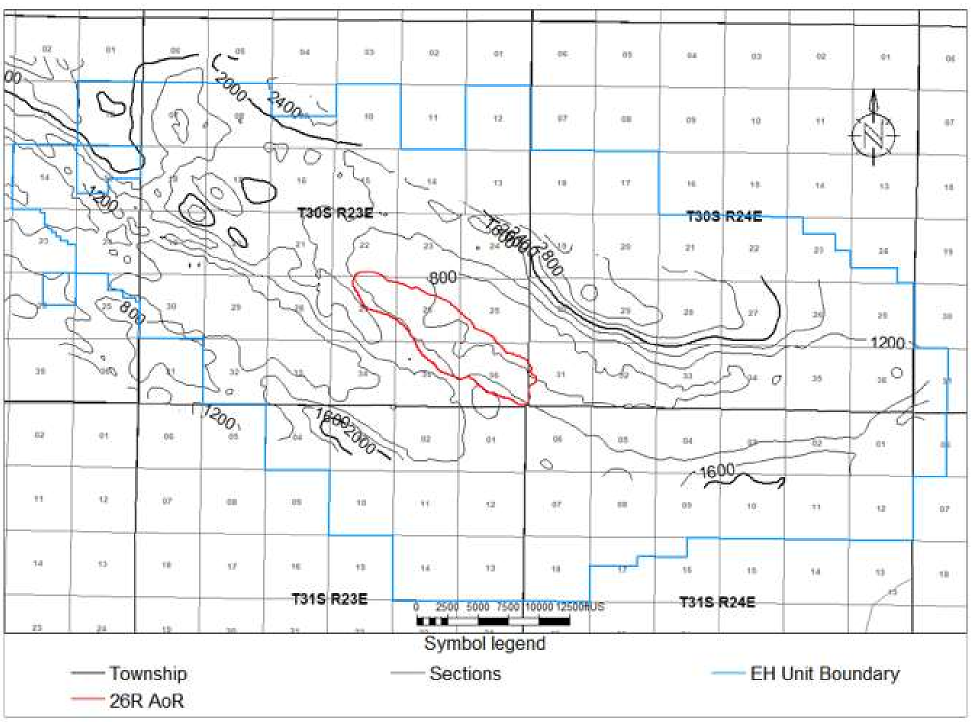
Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the CO_2 injectate in the 26R Monterey Formation sands:

1. There are no reflectors on the 3D seismic that either indicate off-set of the Monterey Formation within the AoR or faults that extend into the confining Reef Ridge Shale (refer to Figure 9).
2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the CO_2 injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,000 feet (Figure 10) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

Figure 10: Reef Ridge Shale isochore map for the Elk Hills Oil Field.



2. Waterflooding and Gas Injection

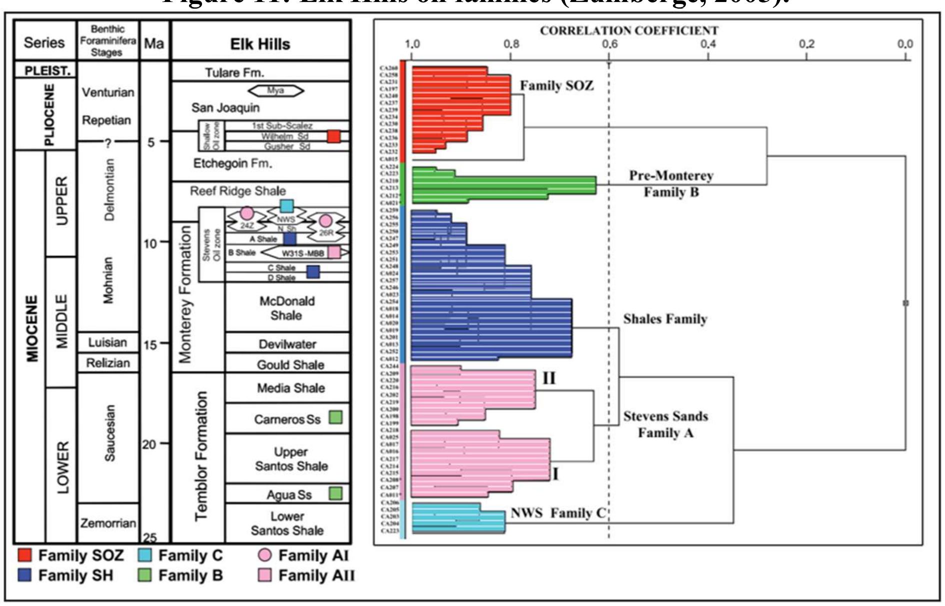
Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control

Board. To date, more than 114 million barrels of water and 841 billion cubic feet of gas have been injected into the 26R Monterey Formation sands. There has been no evidence of water or gas migrating through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically confined.

3. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 11) sourced from the Miocene Monterey Formation (locations for samples are shown in Figure 2) and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

Figure 11: Elk Hills oil families (Zumberge, 2005).



Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Depth and Thickness

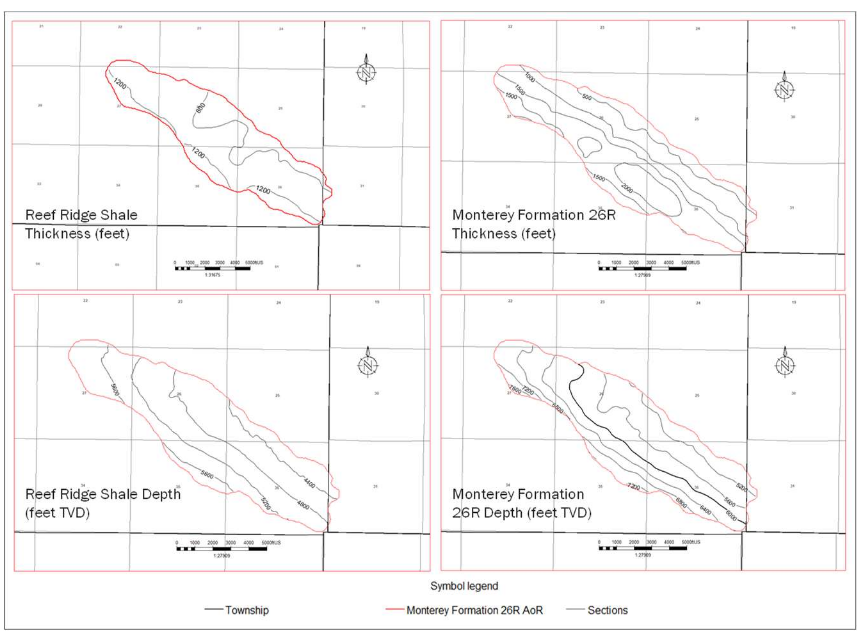
Depths and thickness of the 26R Monterey Formation reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 12) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability is due to deposition of the Monterey Formation sands.
3. Monterey Formation thickness variability is from pinch-out of the reservoir on the 31S structure.

Table 1: Reef Ridge Shale and Monterey Formation 26R thickness and depth for the AoR.

Zone	Property	Low	High	Mean
Confining Zone Reef Ridge Shale	Thickness (feet)	640	1,598	985.1
	Depth (feet TVD)	4,084	5,949	4,992
Reservoir Monterey Formation 26R Reservoir	Thickness (feet)	255	2,497	1,283
	Depth (feet TVD)	4,828	7,827	6,014

Figure 12: Reef Ridge Shale and Monterey Formation 26R thickness and depth maps.

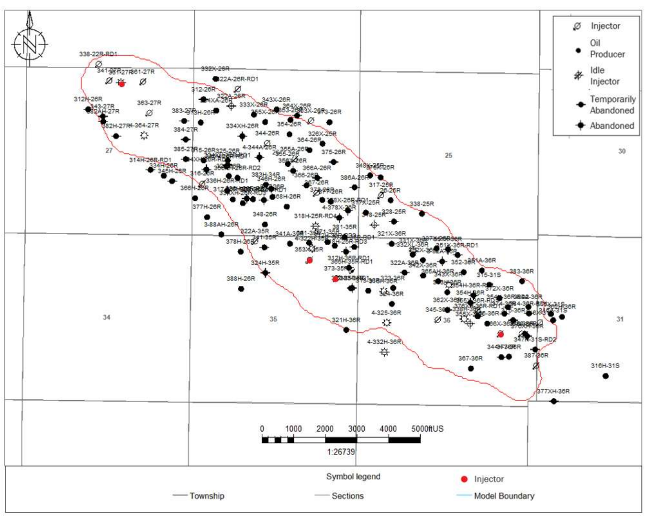


Variability in the thickness and depth of the either the Reef Ridge Shale or the 26R Monterey Formation sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

Facies Changes in the Injection or Confining Zone

The Monterey Formation 26R reservoir and Reef Ridge Shale has been defined with extensive data (Figure 13), with a total of 152 wells and spacing of 400-800 feet. Each of these wells is used to define stratigraphy, lithology/facies and reservoir properties for the static geological model and the maps shown in Figure 12. This quantity and spacing of data is more than sufficient to generate a data driven static model that define facies changes in for the reservoir and confining zone. Based on Monterey Formation 26R operational experience and plume modeling results, there are no facies changes that will either impact injection operations or confinement. During operations at the field, there were no reservoir heterogeneities that would affect injection or facilitate preferential flow. This is supported by Figure 5 that illustrates the continuity of the 26R reservoir.

Figure 13: Well data used to define the Monterey Formation 26R reservoir and confining zone. These wells have open-hole log data that is used to establish, clay volume, porosity, permeability, and facies (sand and shale) that are properties in the static geological model.



Mineralogy

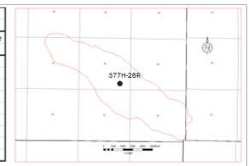
Monterey Formation 26R:

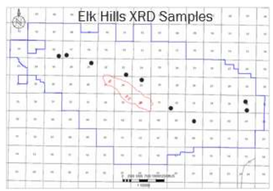
X-ray diffraction (XRD) data has been compiled and compared from 9 wells with a total of 108 data points (Figure 14). XRD samples just north of the 26R AoR are considered consistent with the reservoir because Monterey Formation sands within the Elk Hills Oil Field have similar sediment sources. Clay speciation has been found to be consistent throughout the Elk Hills Field. Well 377H-26R (Figure 14) provides an example of the mineralogy for the reservoir interval in

373-35R. Clean reservoir sand intervals have an average of 39% quartz, 49% potassium feldspar, albite and oligoclase as well as 12% total clay.

Figure 14: Monterey Formation 26R sand mineralogy from well 377H-26R and XRD sample locations in the Elk Hills Oil Field.

	Whole Rock Mineralogy (Weight %)							Relative Clay Abundance (Normalized to 100%)			
Depth	Quartz	K-Feldspar	Plagioclase	Siderite	Pyrite	Gypsum	Total Clay	Illite / Smectite *	Fe-Illite & Mica	Kaolinite	Chlorite
5912.5	38	15	32	0	1	1	13	28	65	4	3
5981.5	40	16	32	0	1	1	10	29	56	11	4
6046.0	40	14	29	0	2	0	15	32	45	20	3
6046.9	37	17	37	0	1	Tr	8	36	45	15	4
6066.4	41	18	32	0	1	0	8	30	41	26	3
6097.1	41	16	34	0	0	0	9	19	53	25	3
6113.3	35	19	34	0	1	0	11	16	46	33	5
6141.0	44	6	17	3	3	1	26	75	22	3	0





Reef Ridge Shale:

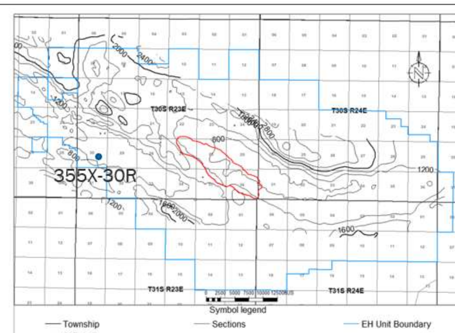
Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 15). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AoR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

Figure 15: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.

FTIR Mineralogy
(Weight Percent)

Depth (ft)	Density (g/cc)	Quartz	Albite	Oligoclase	Andesine	K-Feldspar	Calcite	Dolomite	Pyrite	Opal-A	Opal-CT	Chert	Cristobalite	Total Clay	Kaolinite	Chlorite	Illite+Smectite
5285.5	2.51	12	9	0	10	10	0	0	0	0	26	0	0	33	5	3	25
5290.0	2.38	0	5	0	0	6	2	0	2	0	57	0	19	9	5	0	4
5291.8	2.51	0	7	0	3	9	3	0	3	0	39	11	0	25	9	0	16
5295.5	2.49	0	7	0	0	8	3	0	2	0	42	12	0	26	8	0	18
5299.2	2.52	0	0	0	0	5	0	35	1	0	35	0	19	5	4	0	1
5299.8	2.49	0	7	0	3	7	0	0	2	0	37	13	0	31	9	0	22
5302.2	2.44	0	8	0	0	7	0	0	2	0	39	7	13	24	9	0	15
5304.2	2.50	0	6	0	3	8	1	2	2	0	25	9	10	34	9	0	25
5308.1	2.51	0	7	0	6	5	0	3	0	0	23	17	0	39	11	0	28
5318.0	2.50	0	7	0	3	7	2	0	2	0	34	14	0	31	8	0	23
5325.0	2.52	12	0	0	9	7	0	3	0	0	23	0	0	46	14	0	32
5333.0	2.51	10	7	0	3	6	0	2	1	0	30	0	0	41	12	0	29
5336.9	2.37	0	5	0	0	4	0	0	2	0	63	0	20	6	4	0	2
5338.8	2.48	0	8	0	0	9	2	0	3	0	45	10	0	23	8	0	15
5341.2	2.81	0	0	0	0	3	3	75	1	0	0	12	0	6	0	0	6
5341.7	2.50	9	6	0	4	8	0	0	2	0	34	0	0	37	12	0	25
5346.1	2.78	0	0	0	0	0	4	70	0	0	0	18	0	8	0	0	8
5350.1	2.49	13	5	11	0	3	0	2	0	0	31	0	0	35	12	0	23
5356.0	2.51	16	7	0	5	8	0	2	0	0	25	0	0	37	11	0	26
5361.1	2.82	0	0	0	0	0	2	81	1	0	0	10	0	6	0	0	6
5364.6	2.37	0	0	0	0	9	0	0	1	0	58	0	22	10	5	0	5
5371.0	2.55	0	7	0	2	10	2	0	3	0	25	16	0	35	9	0	26
5380.6	2.37	0	7	0	0	4	1	0	0	0	58	0	16	14	5	0	9
5381.0	2.49	10	5	12	8	8	0	0	0	0	29	0	0	28	4	0	24
5383.3	2.41	0	6	0	0	8	1	1	1	0	47	0	17	19	7	0	12
5386.4	2.39	0	7	0	0	7	1	0	1	0	52	0	17	15	6	0	9
5387.4	2.45	0	7	0	2	7	2	2	0	0	32	7	15	26	8	0	18
5391.4	2.40	0	8	0	0	6	0	0	1	0	51	5	16	13	6	0	7
5398.6	2.51	11	6	0	5	6	2	2	0	0	28	0	0	40	14	0	26
5406.5	2.49	0	6	0	2	7	5	0	0	0	31	13	0	36	11	0	25
5410.9	2.41	0	7	0	0	8	2	0	1	0	46	0	16	20	7	0	13
5416.2	2.45	0	8	0	0	7	0	0	0	0	44	10	0	31	9	0	22
5418.5	2.46	5	6	0	2	8	2	0	0	0	30	0	11	36	11	0	25
5423.6	2.51	0	7	0	0	8	3	0	2	0	33	15	0	32	7	0	25
5433.5	2.51	12	6	0	7	8	0	0	0	0	26	0	0	41	12	0	29
5447.5	2.46	0	8	0	0	6	0	0	1	0	45	13	0	27	8	0	19



335X-30R Reef Ridge Shale confining layer core analysis.

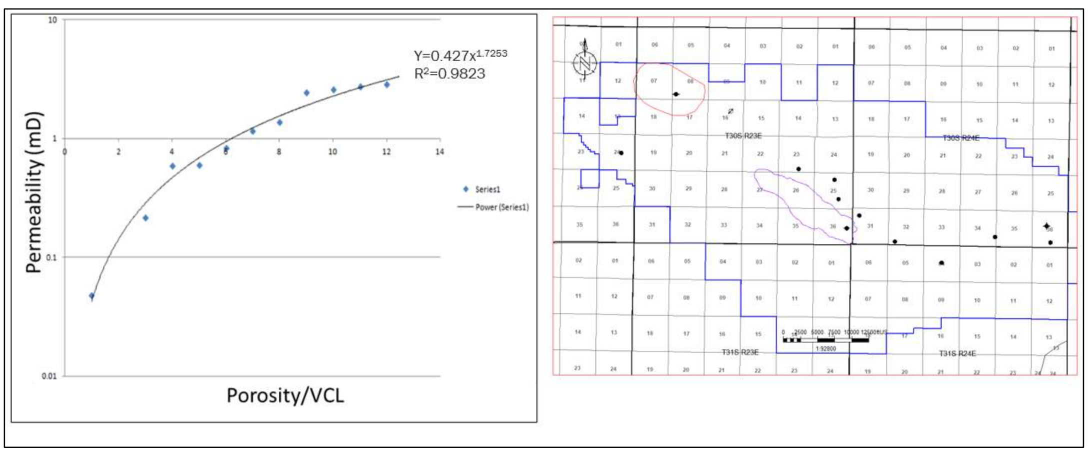
Porosity and Permeability

26R Monterey Formation:

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

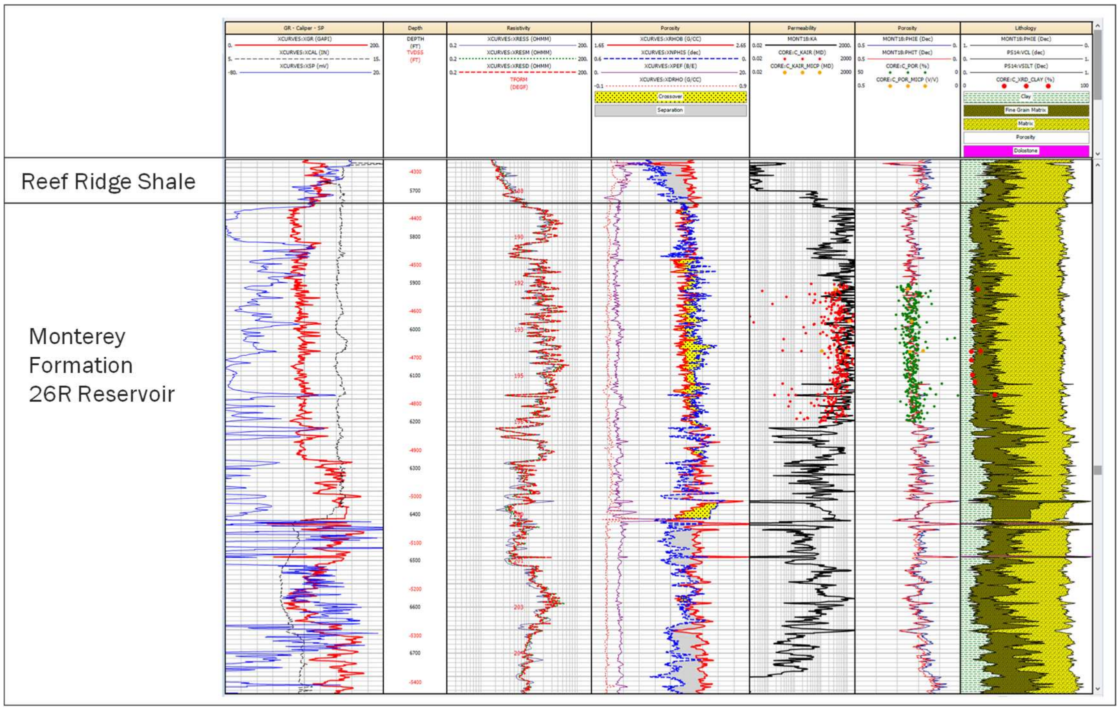
> Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.
>
> Volume of clay is determined by neutron-density separation and is calibrated to core data.
>
> Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 16 below.

Figure 16: Permeability function developed based on mercury injection capillary pressure data and calculated from log derived porosity and clay volume.



In the example below for the 26R Monterey Formation sands, the porosity ranges from 20% - 30% with a mean of 24%. The permeability ranges from 3 mD – 1,500 mD with a log mean of 45 mD (Figure 17).

Figure 17: Porosity and permeability for well 377H-26R, showing the distribution and the input and output log curves.



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2). For each of the project wells, Table 3 shows the average porosity and permeability of the Reef Ridge Shale.

Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.

Sample	Depth (ft)	Porosity (dec)	Permeability (mD)
TEST1	5290	0.0586	0.00007
TEST2	5299.2	0.0351	0.00003
TEST3	5338.8	0.0922	0.0002
TEST4	5361.1	0.137	0.0917
TEST5	5364.4	0.0536	0.00006

TEST6	5380.6	0.0611	0.00007
TEST7	5383.3	0.0794	0.00012
TEST8	5386.4	0.0541	0.00006
TEST9	5391.4	0.102	0.0002
TEST10	5416.2	0.0894	0.0002
TEST11	5447.5	0.0806	0.00011
Average	5368.99	0.07665	0.00844

Table 3: Reef Ridge porosity and permeability for project wells.

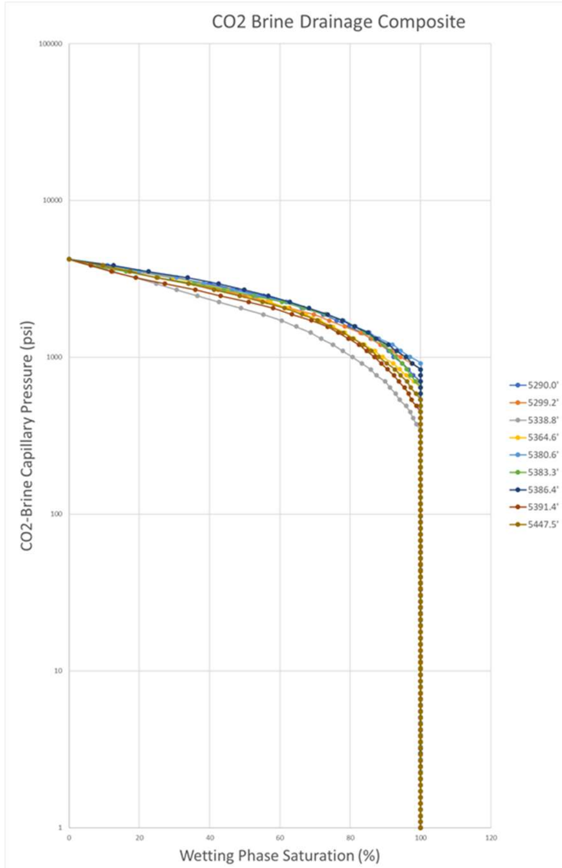
Well	Permeability (mD)	Porosity (%)
376-36R	0.0043	16
353X-35R	0.0005	12
328-25R	0.0174	20
345-36R	0.0012	15
341-27R	0.0002	11
363-27R	0.0002	10
373-35R	0.0001	10

Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a CO_2-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 18). The capillary pressure was determined by applying CO_2-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to CO_2-brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and CO_2-brine, respectively.

Figure 18: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.



Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR and area, 11 wells (Figure 19) had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 22,592 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

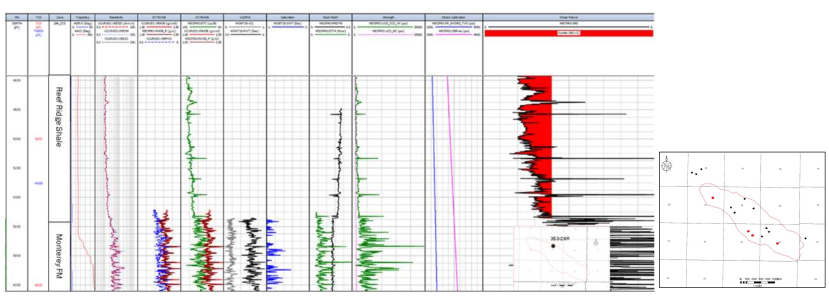
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 353-26R is shown below (Figure 19). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method.

Figure 19: Unconfined compressive strength and ductility calculations for well 353-26R. The Reef Ridge Shale ductility is shaded where less than two.



At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than two, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. The BRI less than two confirms that the Reef Ridge is a ductile confining layer.

The average ductility of the confining zone based on data from 11 wells is 1.59.

The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,385 PSI.

As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the 26R Monterey Formation reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 20 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

Figure 20: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).

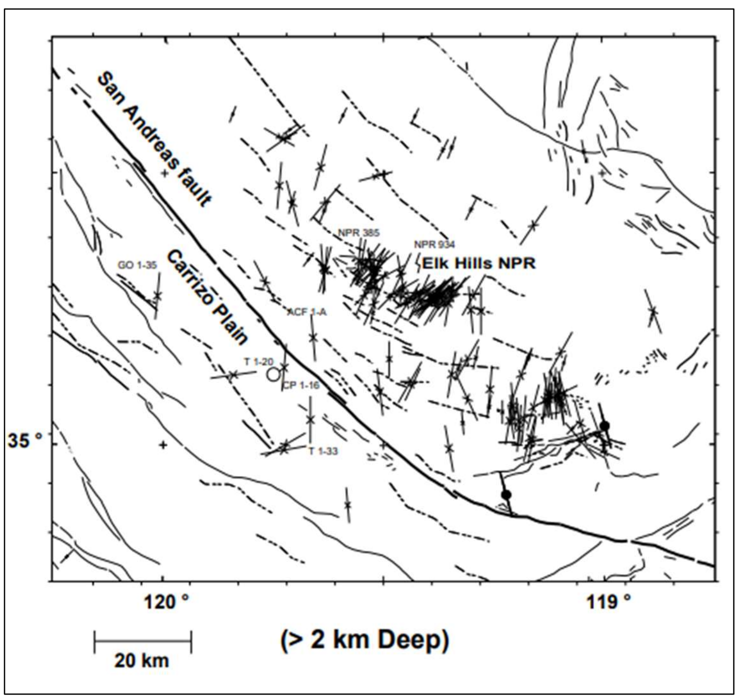


Table 4 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation 26R reservoir.

Table 4: Pressure gradients for the Monterey Formation 26R reservoir and Reef Ridge Shale. The Reef Ridge Shale fracture gradient and pressure will be determined during pre-operational testing. The Monterey Formation fracture gradient is based on a test in well 388-26R. The overburden gradient was determined by integrating density logs.

Stress	Reef Ridge Confining Layer	Monterey Formation
Pore Pressure Gradient (psi/ft)	0.433	0.5
Overburden Gradient (psi/ft)	0.91	0.92
Fracture Gradient (psi/ft)	TBD	0.701

Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by CO_2 injection. A modified Barton-Bandis model can be used to allow CO_2 to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. CO_2 is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow CO_2 to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 5. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

Table 5: Geomechanical modeling results for four scenarios.

GEOMECHANICAL SCENARIO RESULTS	
SCENARIO	**FAILURE PRESSURE, PSI**
BASE CASE	8,306
REDUCED YOUNG'S MODULUS	8,388
REDUCED INJECTION RATE	8,340
THINNER CAP ROCK	7,600

Description:

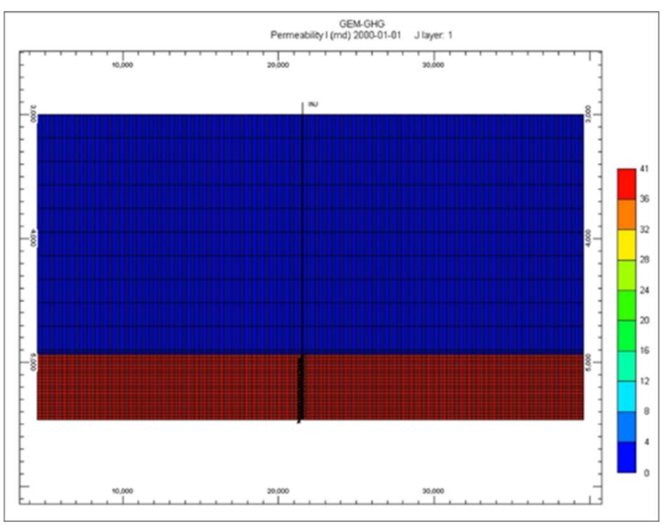
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 21.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of CO_2 with a maximum injection pressure of 10,000 PSI.

Figure 21: Geomechanics Model.

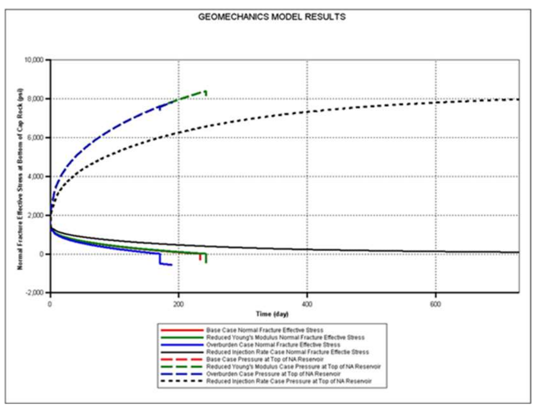


Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 22 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to CO_2 bleeding into the cap rock despite the very low vertical permeability.

Figure 22: Normal Fracture Stress and Pressure for Geomechanics Cases. Base case follows the reduced Young's Modulus case.



Geomechanical Modeling Parameters

The geomechanical parameters used in the modeling were selected to represent a range of values for thickness, poisons ratio and Youngs Modulus. The following is a short description for parameter variability selection:

> **Thickness:** Reef Ridge thickness scenarios for the geomechanical modeling was 795 feet and 1,935 feet. The mean thickness of the Reef Ridge Shale confining layer overlying the Monterey Formation 26R AoR is 985 feet thick (Figure 12) as derived from open-hole log interpretation, which is between the parameters modeled.

Poisson's Ratio: Compressional and shear sonic logs were used to calculate Poisson's Ratio (Yale, 2017).

$$\nu_{dyn} = \nu_{stat} = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)}$$

The following table shows the range of values determined for Poisons Ratio and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case	10	50	90
Confining Layer Reef Ridge	0.23	0.23	0.23	0.29	0.33	0.36
Reservoir 26R	0.25			0.19	0.27	0.35

Young's Modulus: Young's Modulus was calculated using compressional and shear sonic and bulk density logs. The dynamic to static correction applied was the Lacy shale method (Lacy, 1997):

$$E_{dyn} = \frac{\rho V_s^2(3V_p^2 - 4V_s^2)}{(V_p^2 - V_s^2)}$$

- See equation 8.1 in Fjaer et. al, 2008

$$E_{stat} = 0.0428E_{dyn}^2 + 0.2334E_{dyn}$$

- See equation 2 in Lacy, 1997.

The following table shows the range of values determined for Young's Modulus and that the parameters modeled are within the range or more conservative.

	Modeled			Actual		
	Base Case	2nd Case	3rd Case	10	50	90
Confining Layer Reef Ridge	0.9	0.8	0.6	0.6	0.71	0.87
Reservoir 26R	0.725			0.79	0.90	1.07

Seismic History [40 CFR 146.82(a)(3)(v)]

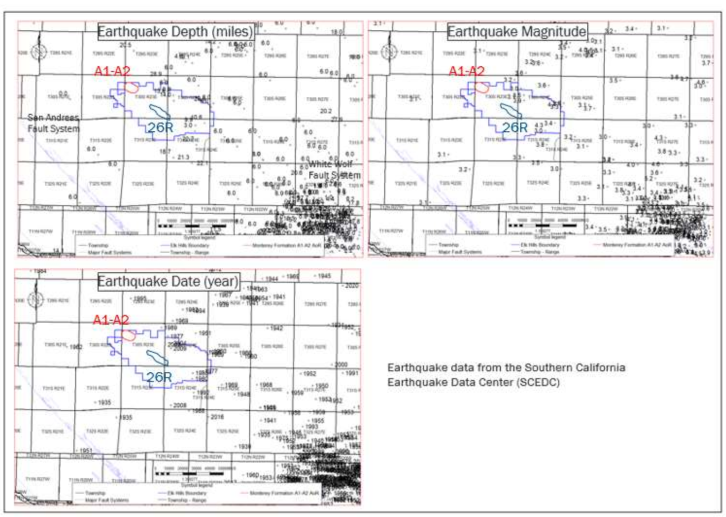
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

There have been no earthquakes in the AoR (Figure 23). In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

Figure 23: Earthquakes in the southern San Joaquin Basin with a magnitude greater than 3 since 1932.



Seismic Risk:

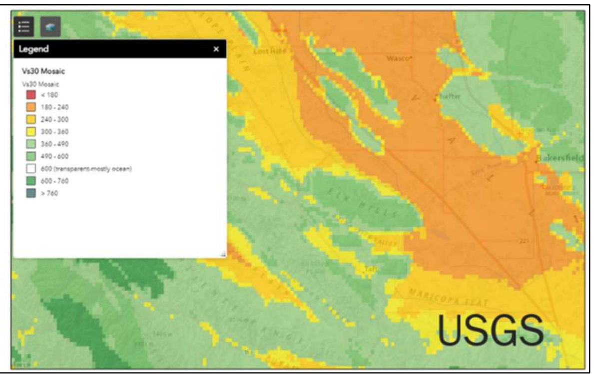
The EHOF has been closely monitored for the effects of seismicity by CTV and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30 means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

Figure 24: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.

Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

Site Class	S-Velocity (Vs) (ft/sec)	S-Velocity (Vs) (m/sec)
A (Hard Rock)	> 5,000	> 1500
B (Rock)	2,500 – 5000	760 – 1500
C (Very Dense Soil and Soft Rock)	1,200 – 2,500	360 – 760
D (Stiff Soil)	600 – 1,200	180 – 360
E (Soft Clay Soil)	< 600	< 180
F (Soils requiring additional response)	< 600, and meeting some additional conditions.	< 180, and meeting some additional conditions.



Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

The following is a summary of CTVs seismic risk:

Has a geologic system free of known faults and fractures and capable of receiving and containing the volumes of CO2 proposed to be injected.

- Extensive historical operations in the Monterey Formation 26R reservoir is valuable experience to understand operating conditions such as injection volumes and reservoir containment. The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
- VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high VS30means (Figure 24) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
- There are no faults or fractures identified in the AoR that will impact the confinement of CO2 injectate.

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events;

- The strategy to limit the injected CO2 to at or beneath the initial reservoir pressure will mitigate the potential for induced seismic events and endangerment of the USDW.
- Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be lower than the fracture gradients of the sequestration reservoir and confining layer with a safety factor (90% of the fracture gradients).
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated; and

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur.
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations.

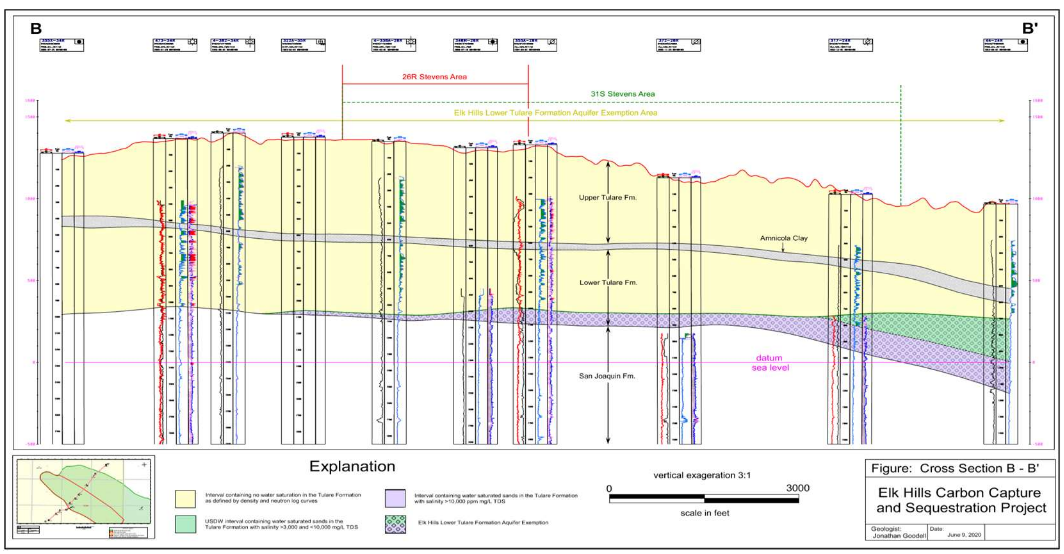
Poses a low risk of inducing a felt seismic event.

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining layer.
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event.
- The operational strategy of keeping the reservoir pressure at or beneath the initial pressure of the reservoir has been designed to reduce the risk for seismic events.

Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

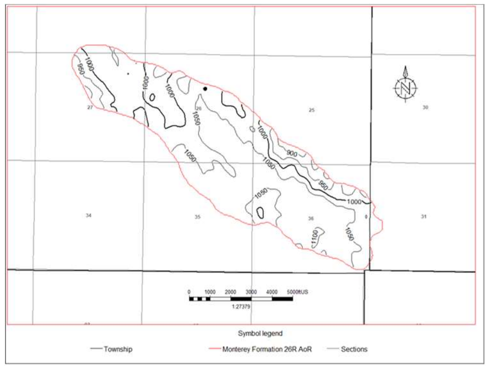
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 25). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

Figure 25: The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands are unsaturated in the 26R area.



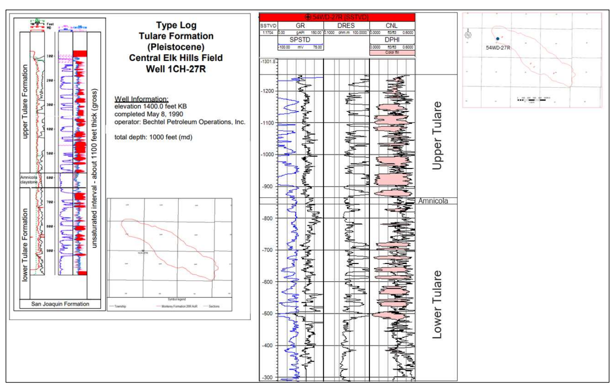
The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 25). The depth is 900 - 1,000 feet and the thickness ranges from 900 – 1,000 feet (Figure 26). The average depth of the Upper Tulare in the AoR is 502 feet TVD. The separation between the Upper Tulare and the Reef Ridge is 4,490 and the injection zone is 5,512 feet.

Figure 26: Tulare Formation isopach map.



The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 27). The characteristic density-neutron crossover (red-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity.

Figure 27: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, and Lower Tulare exempt aquifer.



Tulare Formation (Figure 28) water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum contaminant levels (MCL).

In 2018 the Lower Tulare aquifer was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and
2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

Figure 28: Upper Tulare and Lower Tulare Formation water analysis.

Upper Tulare

Table 4a. WATER SOURCE WELL #43WS-13B
WATER ANALYSIS DATA (mg/kg)

DATE	6-95	7-95	8-95	9-95
SAMPLE #	95094	95150	95182	95189
CONSTITUENTS:				
Calcium, Ca	230	230	220	220
Magnesium, Mg	85	85	92	93
Sodium, Na	1280	1300	1200	1300
Potassium, K	9.2	9.8	8.8	8.6
Iron, Fe	0.4	0.51	0.38	0.54
Hydroxide, OH	0	0	0	0
Carbonate, CO3	0	0	0	0
Bicarb, HCO3	180	190	190	180
Chloride, Cl	1360	1400	1300	1400
Sulfate, SO4	1600	1600	1500	1600
Sulfide, S	<5.0	<5.0	<5.0	<5.0
Totals	4660	4700	4480	4700
Boron, B	4.7	4.6	4.7	4.7
TDS (Grav)	4890	4800	4900	4900
Hardness, CaCO3	920	920	930	930
Alkalinity, CaCO3	150	160	160	150
Sodium Chloride	3690	3700	3500	3800
pH	7.8	8.1	8.0	7.9
Electrical Conductivity	6.99 mmhos/cm	7.02 mmhos/cm	6.99 mmhos/cm	6.99 mmhos/cm
Specific Gravity	1.003	1.003	1.004	1.003
Resistivity	1.43 ohm	1.43 ohm	1.43 ohm	1.43 ohm
NOTE: Sample analysis is from Zalco Laboratory.				

(Source: NPR-1 Ground Water Monitoring Plan, 1995)

Lower Tulare

Water Analysis (General Chemistry)

BCL Sample ID: 1411064-01 | Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

Constituent	Result	Units	PQL	MDL	Method	MB Bias	Lab Quals
Electrical Conductivity @ 25 C (Field Test)	27000	umhos/cm	1.0	1.0	EPA-120.1		
pH (Field Test)	7.25	pH Units	0.05	0.05	EPA-150.1		
Temperature (Field Test)	87.6	F	32.0	32.0	SM-2550B		
Total Calcium	650	mg/L	2.0	0.30	EPA-6010B	ND	A10
Total Magnesium	230	mg/L	1.0	0.38	EPA-6010B	0.75	A10
Total Sodium	4700	mg/L	10	1.0	EPA-6010B	ND	A01
Total Potassium	31	mg/L	20	2.6	EPA-6010B	ND	A10
Bicarbonate Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Carbonate Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Hydroxide Alkalinity as CaCO3	ND	mg/L	8.2	8.2	EPA-310.1	ND	
Total Alkalinity as CaCO3	59	mg/L	8.2	8.2	EPA-310.1	ND	
Bromide	50	mg/L	5.0	2.2	EPA-300.0	ND	A01
Chloride	10000	mg/L	50	6.7	EPA-300.0	20	A01
Fluoride	ND	mg/L	2.5	0.70	EPA-300.0	ND	A10
Nitrate as NO3	ND	mg/L	22	5.5	EPA-300.0	ND	A10
Sulfate	320	mg/L	50	9.0	EPA-300.0	19	A01
pH	7.47	pH Units	0.05	0.05	EPA-150.1		S05
Electrical Conductivity @ 25 C	26100	umhos/cm	1.00	1.00	EPA-120.1		
Total Dissolved Solids @ 180 C	20000	mg/L	1000	1000	EPA-160.1	ND	

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

Geochemistry [40 CFR 146.82(a)(6)]

Geochemistry 26R Reservoir:

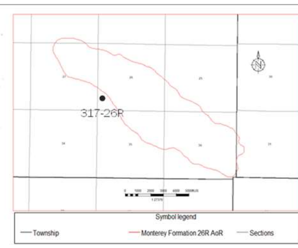
The 26R Monterey Formation reservoir has a gas cap that overlies a thin oil band and a basal water zone. CTV and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Geochemical water analysis for the 26R Monterey Formation reservoir has been completed across the AoR and collected since reservoir discovery as part of routine surveillance. This data is consistent through time and over the AoR, Figure 29 shows the geochemical water analysis for well 317-26R.

Figure 29: Monterey Formation 26R reservoir water geochemistry from well 317-26R.

RADICALS		PARTS PER MILLION MILLIGRAMS PER LITER	REACTING VALUE EQUIVALENTS PER MILLION	REACTING VALUE PERCENT
SODIUM +Potassium	Na+K	8775	381.71	49.10
CALCIUM	Ca	92	4.59	0.59
MAGNESIUM	Mg	19	1.56	0.20
BARIUM	Ba	57	0.83	0.11
STRONTIUM	Sr			
SULPHATE	SO_4	1198	24.92	3.22
CHLORIDE	Cl	11424	322.16	41.61
CARBONATE	CO_3			
BICARBONATE	HCO_3	2441.8	40.05	5.17
HYDROXIDE	OH			
IODIDE	I			
SILICA	SiO_2	50		
IRON, ALUMINA	R_2O_3			
TOTAL		24056.8	775.82	100.00

GROUP	CHEMICAL CHARACTER	MISCELLANEOUS		
ALKALIS	PRIMARY SALINITY	BORON	42.46	PPM
EARTHS	SECONDARY SALINITY	HYDROGEN SULFIDE	3.6	
STRONG ACIDS	PRIMARY ALKALINITY	EQUIVALENT SALT	23944	PPM
WEAK ACIDS	SECONDARY ALKALINITY	RESISTIVITY @ 77°F	0.24	O.M.
Ca/EARTHS		CHLORINITY	18846	PPM
CHLORIDE SALINITY		SPECIFIC GRAVITY	1.017	
SULPHATE SALINITY	CARBONATE/CHLORIDE	pH	8.2	

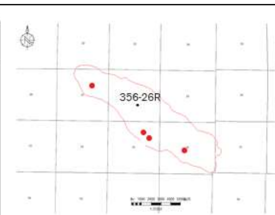


The hydrocarbon composition for the Monterey Formation 26R reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 30 shows the results of the hydrocarbon composition for well 356-26R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

Figure 30: Monterey Formation reservoir hydrocarbon analysis from well 356-26R.

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PERCENT	WEIGHT PERCENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide	Nil	Nil			
Carbon Dioxide	1.29	0.65			
Nitrogen	0.07	0.02			
Methane	38.83	7.16			
Ethane	8.38	2.89			
Propane	7.05	3.57			
iso-Butane	1.38	0.92			
n-Butane	3.92	2.61			
iso-Pentane	1.50	1.24			
n-Pentane	1.72	1.42			
Hexanes	2.15	2.12			
Heptanes plus	33.71	77.40	0.8516	34.5	200
	100.00	100.00			



26R Monterey Formation Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the CO_2 injectate:

1. The 26R Monterey Formation reservoir will store 7% of the injectate CO_2 in aqueous phase with water saturations of 34% saturation in the gas cap, 25% in the oil band and 100% in the basal water.
2. Residual oil saturation (15- 37%) in the 26R Monterey Formation reservoir will dissolve 20% of the CO_2 injectate.
3. The Monterey Formation has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of CO_2 and carbonic acid and any dissolution or changes that occur will stay on grain surfaces.

The oil and water CO_2 trapping mechanisms have been incorporated in the computational modeling and is discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the CO_2 injectate.

Geochemistry Etchegoin Reservoir:

The Etchegoin Formation reservoir geochemistry is shown in Figure 31. The total dissolved solids of the water is 31,725.4 from well 22H-26R, demonstrating that the reservoir is not of USDW water quality.

Figure 31: Etchegoin Formation water geochemistry from well 22H-26R in the AoR.

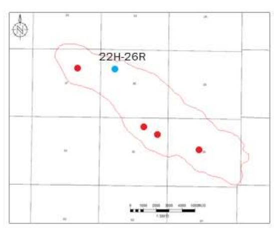
Well Name: 24H-26R
Sample Point: Wellhead
Sample Date: 2/4/2014
Sample ID: WA-265899

Scaling potential predicted using ScaleSoftPitzer from Brine Chemistry Consortium (Rice University)

Sample Specifics	
Test Date:	2/14/2014
System Temperature 1 (°F):	200
System Pressure 1 (psig):	2000
System Temperature 2 (°F):	60
System Pressure 2 (psig):	15
Calculated Density (g/ml):	1.019
pH:	6.50
Calculated TDS (mg/L):	31725.40
CO2 in Gas (%):	
Dissolved CO_2 (mg/L)):	360.00
H_2S in Gas (%):	
H2S in Water (mg/L):	2.50

Analysis @ Properties in Sample Specifics			
Cations	*mg/L*	*Anions*	*mg/L*
Sodium (Na):	11623.80	Chloride (Cl):	19000.00
Potassium (K):	0.10	Sulfate (SO_4):	0.00
Magnesium (Mg):	122.00	Bicarbonate (HCO_3):	414.80
Calcium (Ca):	520.00	Carbonate (CO_3):	
Strontium (Sr):	0.00	Acetic Acid (CH_3COO)	
Barium (Ba):	22.60	Propionic Acid (C_2H_5COO)	
Iron (Fe):	21.30	Butanoic Acid (C_3H_7COO)	
Zinc (Zn):	0.00	Isobutyric Acid ($(CH_3)_2CHCOO$)	
Lead (Pb):	0.00	Fluoride (F):	
Ammonia NH_3:		Bromine (Br):	
Manganese (Mn):	0.79	Silica (SiO_2):	

Notes:
80F / 200psi
Conductivity at 70F - 0.0496 S/cm



Site Suitability [40 CFR 146.83]

The 26R Monterey Formation reservoir in the 31S anticline was discovered in the 1940's and developed in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the 26R Monterey Formation reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

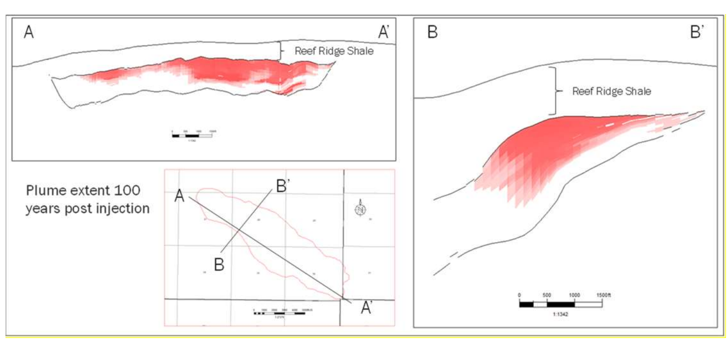
A key component of the 26R Monterey Formation reservoir characterization was the development of a geo-cellular model, which is used to assess CO_2 plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement, and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale).

CO2 Injectate Confinement:

Confinement of CO_2 injected into the storage reservoir is supported by the following:

1. Monterey Formation 26R reservoir hydrocarbons were confined for several million years.
2. The Reef Ridge Shale primary confining layer is 800-1,000 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 841 billion cubic feet of gas and 114 million barrels of water with no leakage.
3. Cross section A-A' (Figure 32) shows confinement of the injected CO_2 plume by up-dip pinch-out of the reservoir on the anticline structure and lateral confinement by reservoir edges. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that CO_2 does not migrate beyond the edges of the anticline structure or into the Reef Ridge Shale.

Figure 32: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the Monterey Formation 26R sand facies and the edges of the reservoir.



Storage capacity for the Monterey Formation 26R storage reservoir based on computational modeling results is up to 38 million tonnes of CO_2. This is sufficient capacity for the total proposed injectate volume.

References:

1. Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.
2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
4. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'37.9057"W

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data

- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

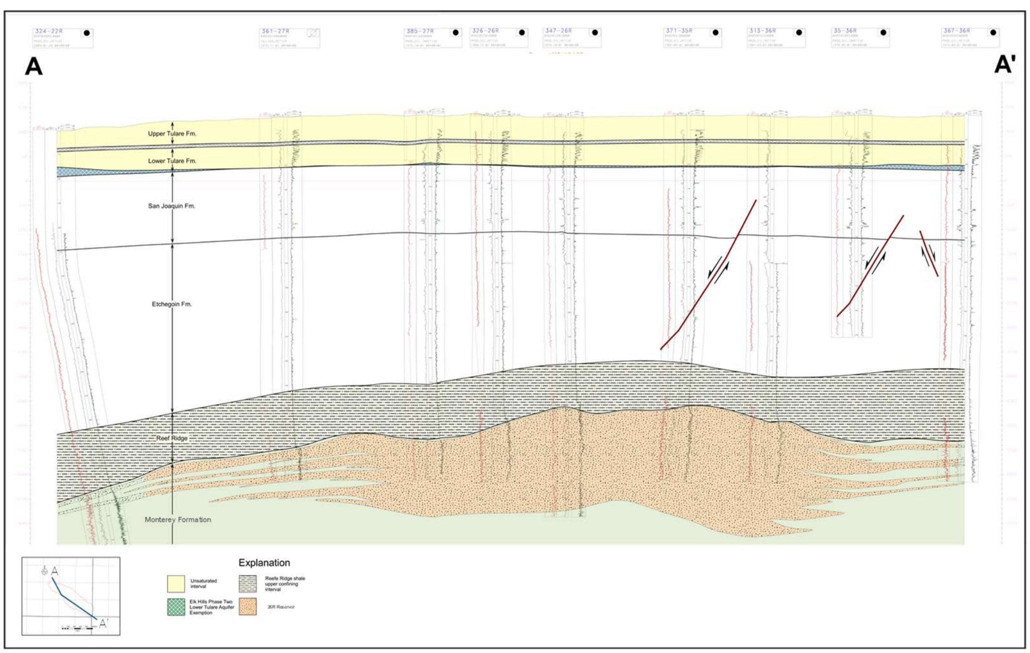
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



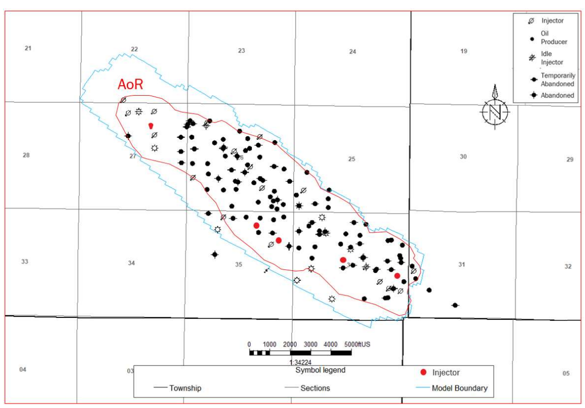
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (figure 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was “blown-down”, depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

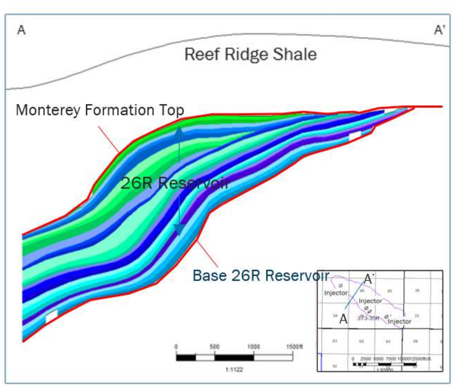
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4) that is dependent on porosity and clay volume.

Figure 4: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

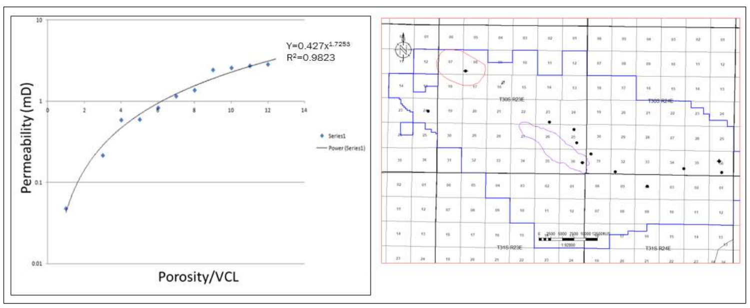


Figure 5: Monterey Formation 26R sands porosity and permeability distribution in the static model.

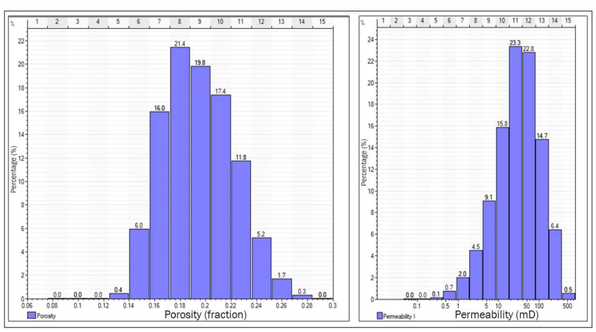
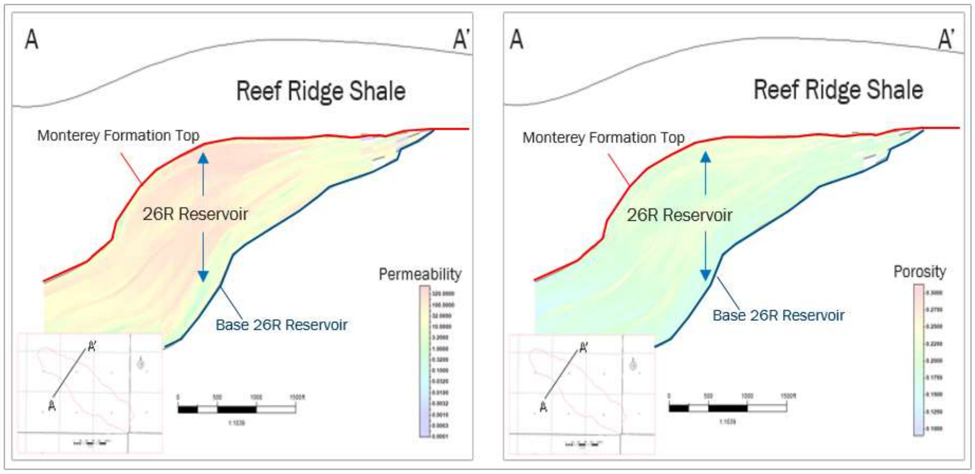


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 6: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.

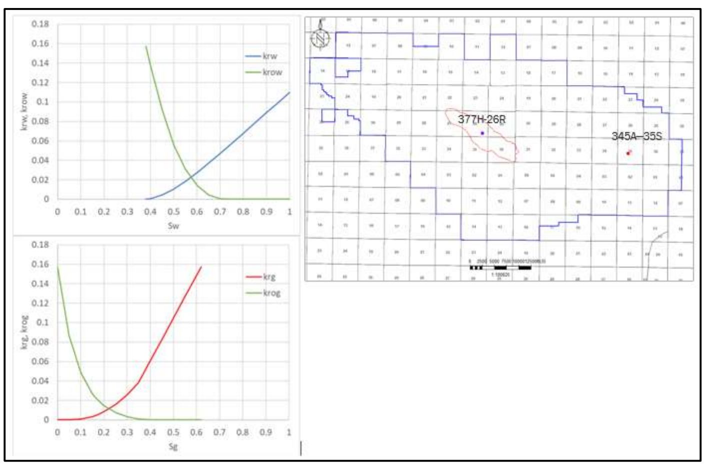
	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 7 shows the relative permeability curves used in the computational modeling.

Figure 7: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

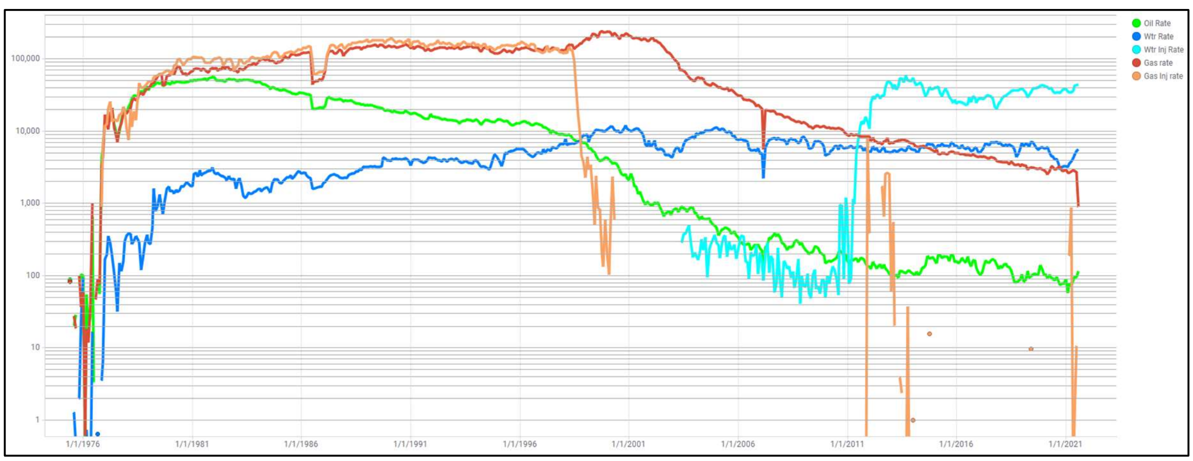
2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 8) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 8) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

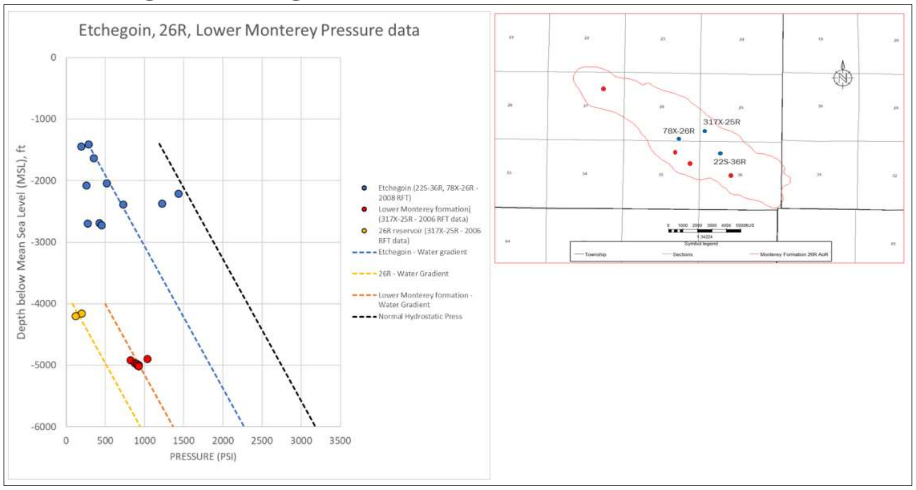
    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

Figure 8: Monterey Formation 26R production and injection data.



Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 9 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Figure 9 : Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	**Value or Range**	**Units**	**Corresponding Elevation (ft, below Mean Sea Level)**	**Data Source**
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	 6121906 2290081	 6126556 2289316	 6121940 2290248	 6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	 6807 / 7086 7109 / 7426	 6097 / 6101 7710 / 7720	 6625 / 6810 8373 / 8545	 6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the time being for the simulation studies. Table 7 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 7: CO2 injectate properties at reservoir conditions

Injectate property	At start of injection	At end of injection
Viscosity, cp	0.019	0.044
Density, kg/m3	16.6	544.8
Salinity, ppm	NA	NA
Compressibility factor, Z	0.97	0.59

The following maps (Figure 10) and cross-sections (Figure 11) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 12 shows the average pore volume pressure vs time.

Figure 10: Plan view showing the plume development through time. Plume is at its greatest extent at 20 years post injection.

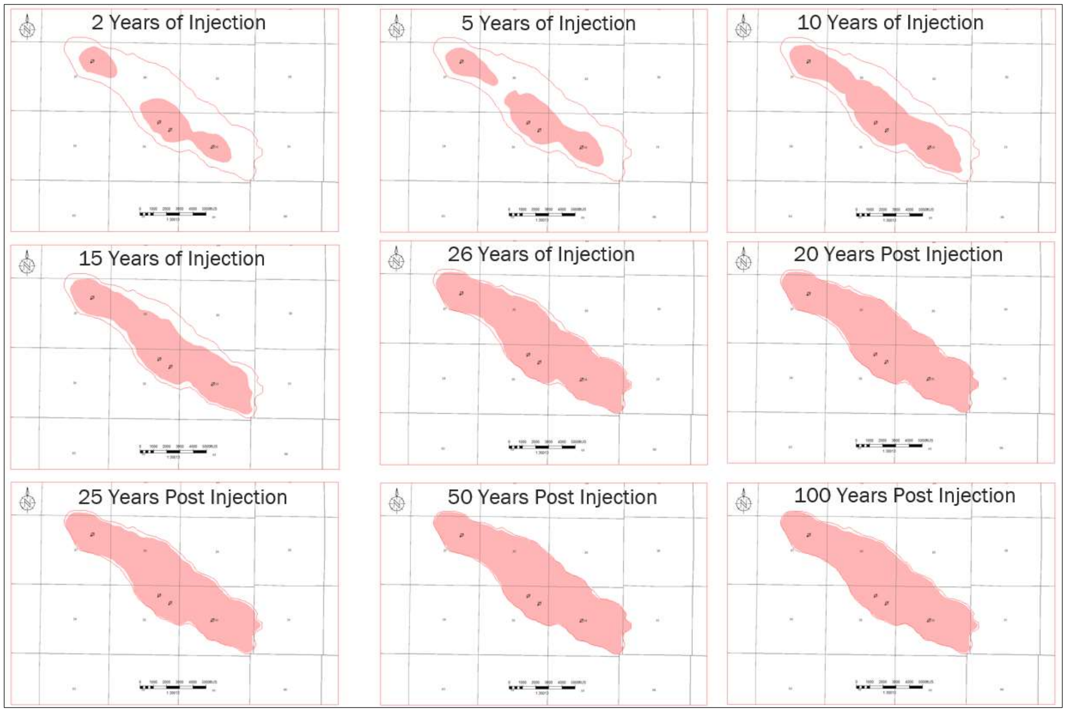


Figure 11: Cross-sections showing the plume development through varying times through the project.

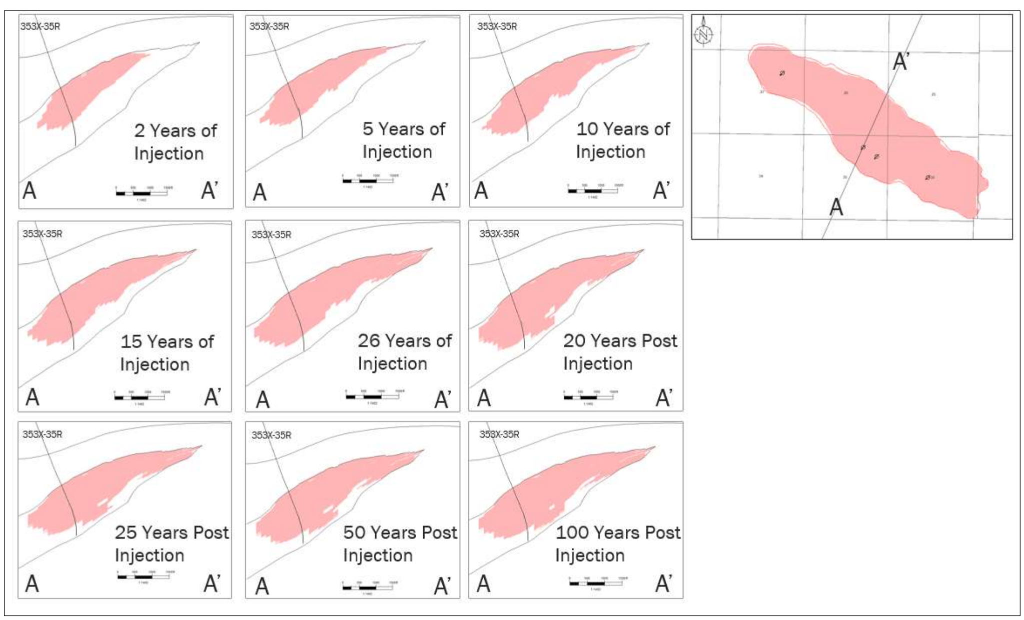
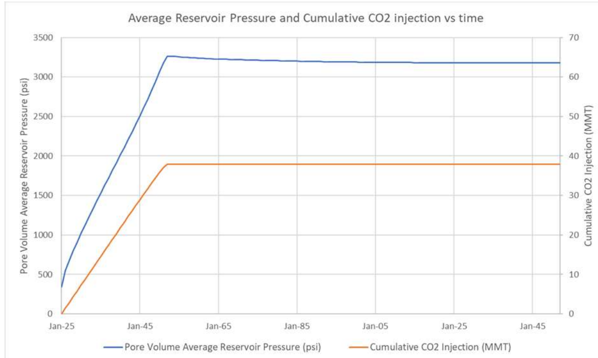
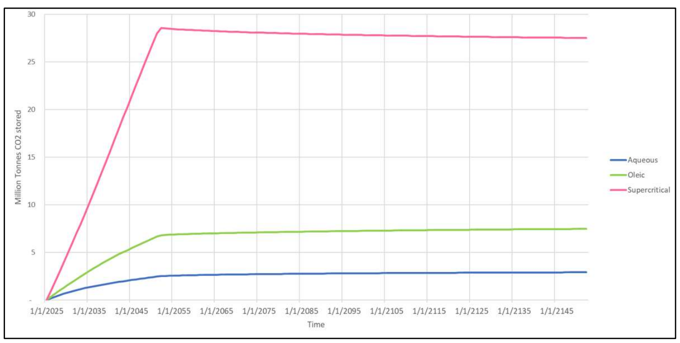


Figure 12: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 13 shows the cumulative storage for each of the mechanisms.

Figure 13: Storage mechanism through time for the 26R reservoir.



Model Calibration and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO_2 storage for the different cases, there was minimal change to the maximum extent of the CO_2 plume.

Table 8 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 14 compare the CO2 plume extent for Case X: Permeability reduced by 10% against the Base Case.

Table 8: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR

Figure 14: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.

These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

AoR Delineation

The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

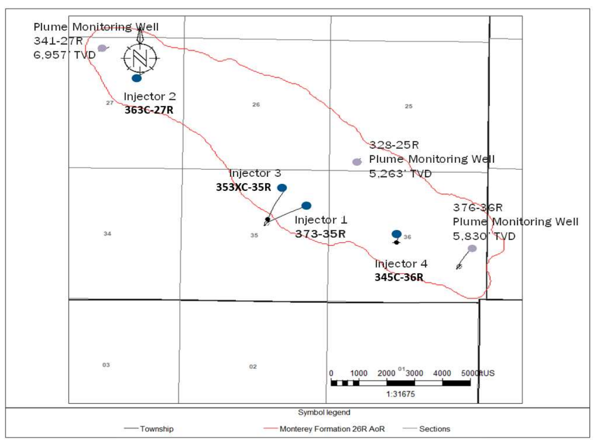
Figure 15 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 15: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

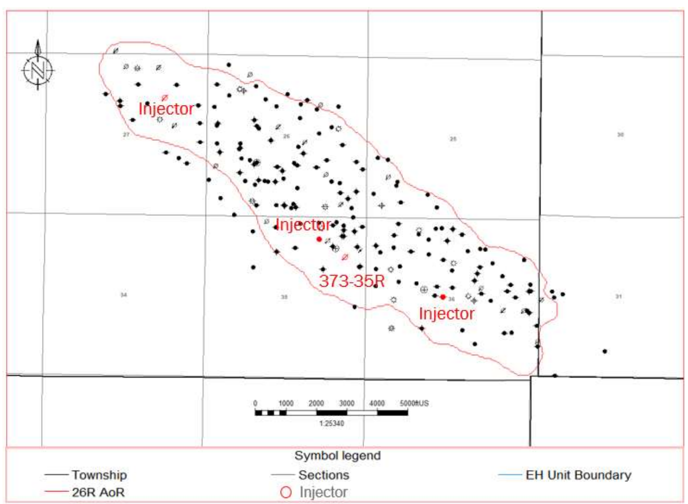
Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 9 is a summary of the AoR wells by type. Figure 16 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 9: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 16: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the “wellhead” level using API-10 and at the “wellbore” level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 10), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 10: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

   a. The presence of faults near the confining zone that indicates propagation into the confining zone.

   b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director within six months of an event to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN 40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC	2	05/31/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

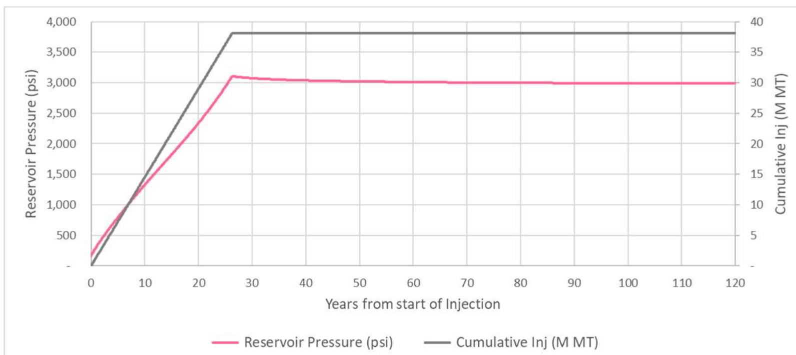
Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize fairly immediately after injection ceases with < 5psi/year change expected within the first year after end of injection. Injection limits will be based on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

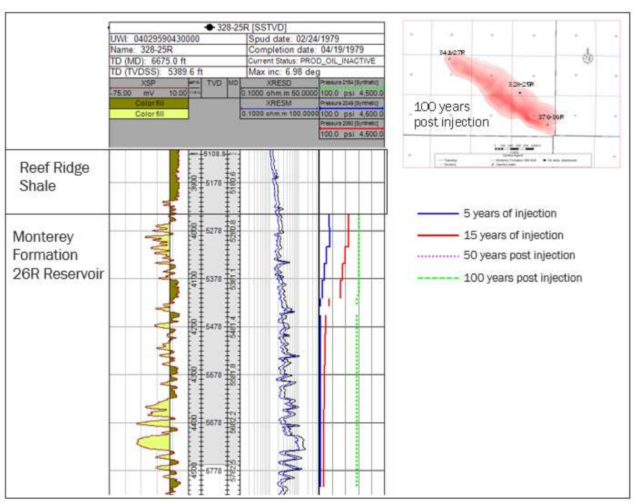
The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

Figure 1: Reservoir pressure and Cumulative injection.



Pressure at 50 and 100 years post injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

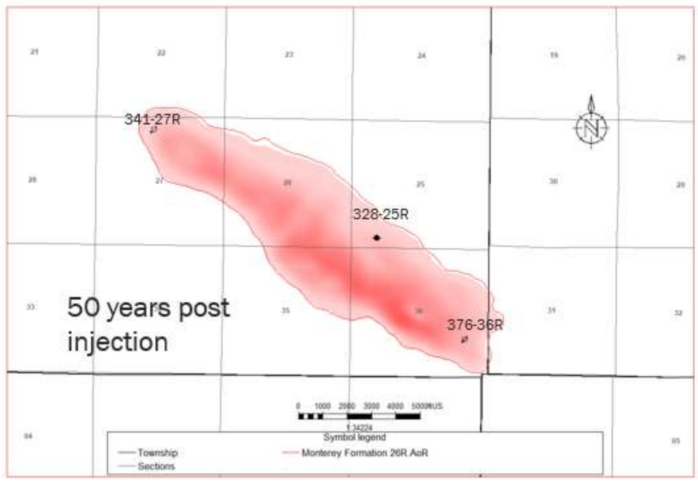
Figure 2: Pressure at the 328-25R monitoring well. Pressure at 50 and 100 years post injection are the same indicating plume stabilization.



Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 3: Map of the predicted extent of the CO2 plume 50 years post injection with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.



Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring.

> Pressure monitoring of the Monterey Formation 26R storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed every five years for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Tulare Formation	Fluid sampling	Shallow Monitoring Well	AoR	Annual
	Pressure and Temperature Monitoring	Shallow Monitoring Well	AoR	Continuously
Etchegoin Formation	Fluid sampling	355X-26R	AoR	Annually
	Pressure and Temperature Monitoring	355X-26R	AoR	Continuously

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Tulare Formation	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B

Parameters	Analytical Methods
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PLUME MONITORING			
Monterey Formation 26R	Fluid Sampling	341-27R, 328-25R and 376-36R	Annual
INDIRECT PLUME MONITORING			
Monterey Formation 26R	Pulse neutron logging	341-27R, 328-25R and 376-36R	Every five years

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Monterey Formation 26R	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1)	ICP-OEC EPA 200.7/6010B
Cations (Ca, FE, K, Mg, Na and Si)	ICP-OEC EPA 200.7/6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300
Dissolved CO2	SM 4500-CO2-C
Alkalinity	SM 2510 B
pH	EPA 150.1 / SM4500-H+B
Total Dissolved Solids (TDS)	SM 4500 C
Specific Conductance (field)	SM 2510 B
Dissolved Methane	RSK – 175 / Gas Chromatography
Temperature (field)	Thermocouple
Pressure	Pressure Gauge

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FRONT MONITORING			
Monterey Formation 26R	Pressure and Temperature	341-27R, 328-25R and 376-36R	Continuous
INDIRECT PRESSURE-FRONT MONITORING			
All strata	Seismicity	AoR	Continuous

Figure 4: Map showing AoR and well locations for monitoring.

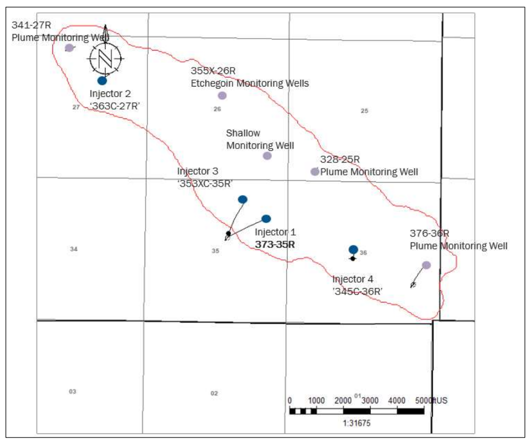
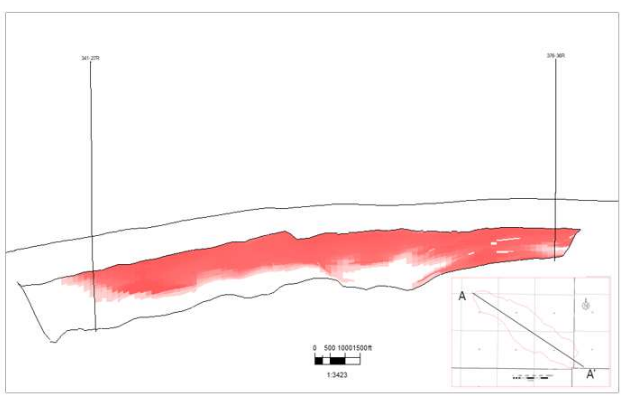


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.



Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

<u>Non-Endangerment Demonstration Criteria</u>

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director as per 40 CFR 143.93(b)(2) or (3).

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)

3. Composition and volume of the injected CO_2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO_2 sequestration, the period of injection and the volume of CO_2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.

4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

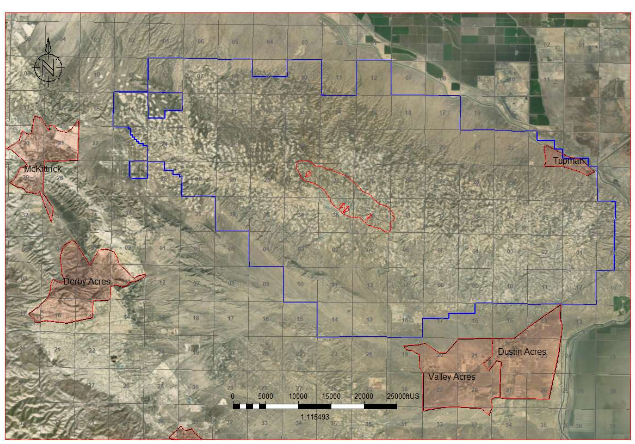
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);
- Potential Brine or CO2 Leakage to a USDW;
- CO_2 leakage to USDW or land surface; or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/post-injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the CTV I Elk Hills 26R Project.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the CTV I Elk Hills 26R Project.

- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the CTV I Elk Hills 26R Project.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
  - Initiate shutdown plan.
  - Shut-in injection well and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
  - Verify whether contamination has occurred via handheld CO_2 monitors.
  - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the CTV I Elk Hills 26R Project.
  - Shut-in injection well and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage into a USDW.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits for the pressure gauge will be 0.001 PSI and pH of 0.2.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
  - Initiate shutdown plan.
  - Contact security to restrict access to the CTV I Elk Hills 26R Project.
  - Shut-in injection well and vent CO_2 from surface facilities.
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
    - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
    - Remediate unacceptable impacts to the affected USDW.
  - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
  - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
  - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
  - If there is a well integrity issue refer to the Mechanical Integrity Failure scenario.

    - If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

Severity: Serious to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the CTV I Elk Hills 26R Project.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If there is contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
    - Communicate with CTV personnel and local authorities to initiate evacuation procedures.

    - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the CTV I Elk Hills 26R Project.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the CTV I Elk Hills 26R Project site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Major

Timing of event: Injection or post injection phases.

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection wells.

Operating State	**Threshold Condition[1,2]**	**Response Action[3]**
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the well if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and issue corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual rate reduction plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected, endangerment and CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination is detected, endangerment and CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Review seismic and operational data. 11. Report findings to the UIC Program Director and issue corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Travis Hurst (661- 342-2409)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Phone Number
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilites, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintainence, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintainence of personal monitors, portable multi-gas monitors and stationary montiors throughout the facility.

Carbon Dioxide Haxards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage with exersise and drills simulating potential emergency situations.

WELL CONSTRUCTION, OPERATING AND PLUGGING DETAILS

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.2743°N / 119.4577°W

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow

formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

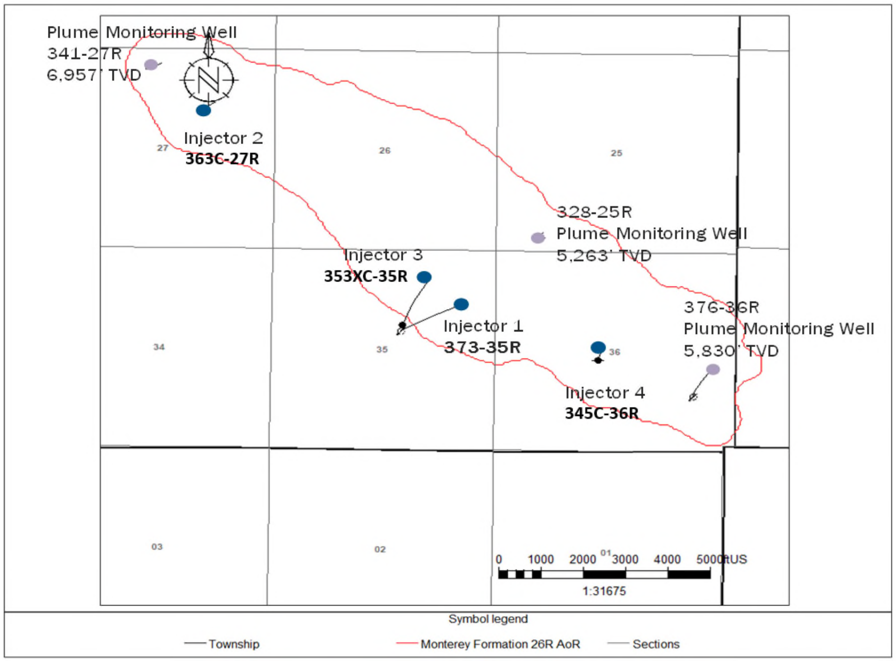


Figure 1: Map showing the location of injection wells and monitoring wells.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

[redacted]

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

Table 2: Tubing Specifications

[redacted]

Table 3: Packer Specifications

[redacted]

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 345C-36R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Well Operations

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum

Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1015 psi and 1993 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1515 psi and 3555 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable downhole injection pressure is 3,847 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	1888	psig
Downhole	3847	psig
Injection Pressure @ Target rate	Expected range over project life	
Surface Start / End	1,015 / 1,515	psig
Downhole Start / End	1,993 / 3,555	psig
Target Injection Rate	18.75 993	mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End	100 / 995	psig
Downhole Start / End	2626 / 3521	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well 345C-36R, CTV expects a target injection rate of 18.75 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3,555 psi. A threshold of 10% over the above injection rate and 5% above the expected bottom hole injection pressure, not to exceed maximum allowable pressure, will be used to configure automation and alarms, which equates to 20.6 million cubic feet per day and 3,733 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system

and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 6: Plugging details

[redacted]

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method

may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATING AND PLUGGING DETAILS

CTV I ELK HILLS 26R PROJECT

Injection Well 353XC-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.3768°N / 119.4732°W

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_353XC-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow

formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

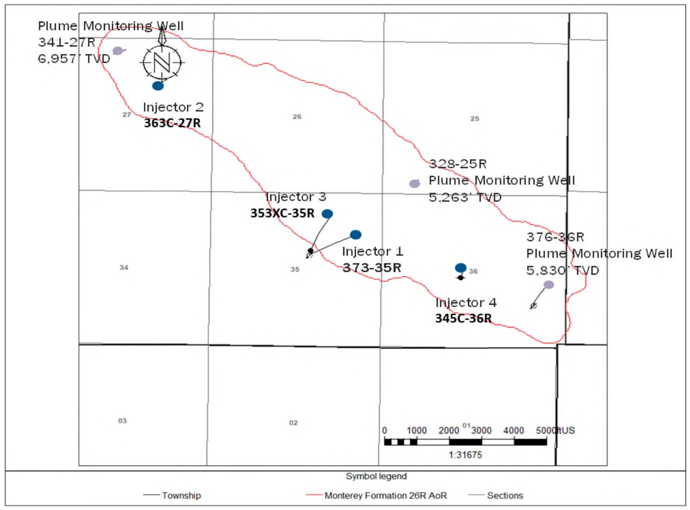


Figure 1: Map showing the location of injection wells and monitoring wells.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid

- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

[redacted]

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

Table 2: Tubing Specifications

[redacted]

Table 3: Packer Specifications

[redacted]

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 353XC-35R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Well Operations

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum

Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1005 psi and 1739 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1550 psi and 3787 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable downhole injection pressure is 4180 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	1,997	psig
Downhole	4,180	psig
Injection Pressure @ Target rate	Expected range over project life	
Surface Start / End	1,005 /1,550	psig
Downhole Start / End	1,739 / 3,787	psig
Target Injection Rate	18.75 993	mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End	100 / 990	psig
Downhole Start / End	2,869 / 3,758	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well 353XC-35R, CTV expects a target injection rate of 18.75 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3,787 psi. A threshold of 10% over the above injection rate and 5% above the expected bottom hole injection pressure, not to exceed maximum allowable pressure, will be used to configure automation and alarms, which equates to 20.6 million cubic feet per day and 3,976 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system

and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 6: Plugging details

[redacted]

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method

may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

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CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATING AND PLUGGING DETAILS

CTV I ELK HILLS 26R PROJECT

Injection Well 363C-27R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.2779°N / 119.4535°W

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_363C-27R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow

formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

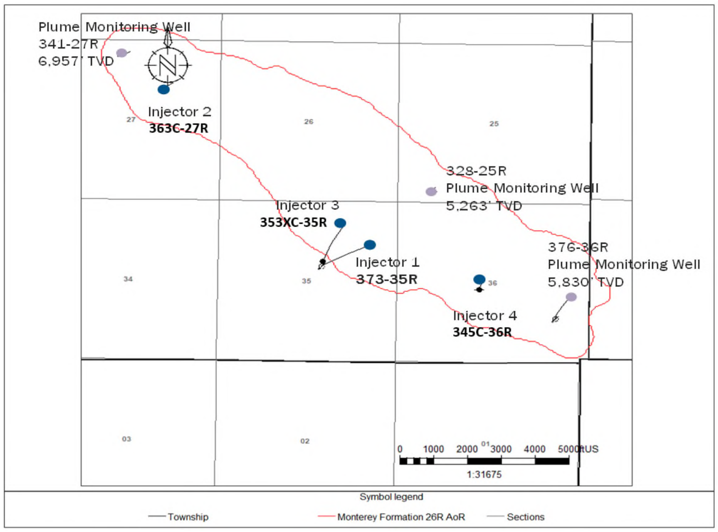

Figure 1: Map showing the location of injection wells and monitoring wells.

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Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors

- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
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- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

[redacted]

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

Table 2: Tubing Specifications

[redacted]

Table 3: Packer Specifications

[redacted]

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120’ during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 363C-27R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

<u>Well Operations</u>

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum

Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1007 psi and 1784 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1375 psi and 3558 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable downhole injection pressure is 4226 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	2,020	psig
Downhole	4,226	psig
Injection Pressure @ Target rate	Expected range over project life	
Surface Start / End	1,015 /1,375	psig
Downhole Start / End	1,784 / 3,558	psig
Target Injection Rate	18.75 993	mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End	100 / 736	psig
Downhole Start / End	2,888 / 3,524	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well 363C-27R, CTV expects a target injection rate of 18.75 million cubic feet per day for which the maximum expected bottom hole injection pressure is 3,558 psi. A threshold of 10% over the above injection rate and 5% above the expected bottom hole injection pressure, not to exceed maximum allowable pressure, will be used to configure automation and alarms, which equates to 20.6 million cubic feet per day and 3,736 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system

and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 6: Plugging details

[redacted]

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method

may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

- If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

WELL CONSTRUCTION, OPERATING, AND PLUGGING DETAILS

Elk Hills 26R Storage Project

Injection Well 373-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project
373-35R

Facility Contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35°19'40.9189"N / 119°32'41.9057"W

Version History

File Name	Version	Date	Description of Change
Attachment G – CoP Details_373-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

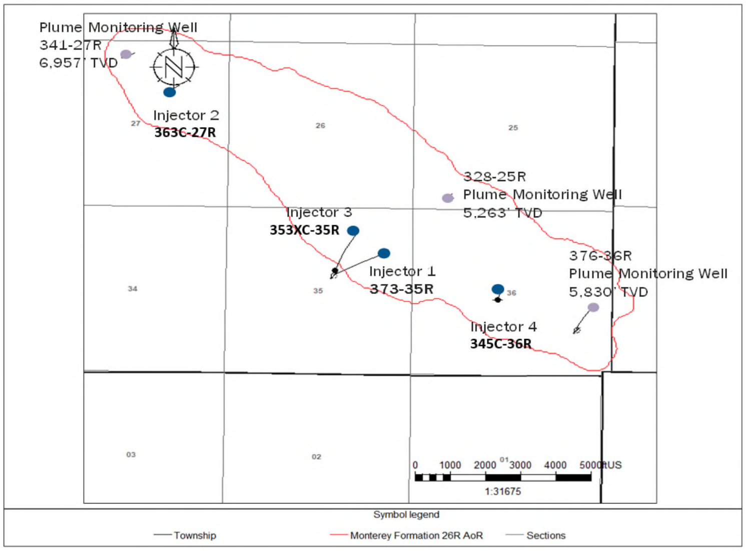


Figure 1: Map showing the location of injection wells and monitoring wells.

Injection well 373-35R is an existing well approved for water injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 4.7 million barrels of water. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity (MIT) and standard annular pressure (SAPT) tests to ensure internal and external mechanical integrity.

The *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

373-35R was drilled in 1982, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors.
2. Although no USDW is present, multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement, and each casing string was cemented to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval within the Monterey and Reef Ridge formations (from base of 7" casing to ~6600 feet).
5. Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous injection conditions.
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

1. Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
2. Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
3. Packer – corrosion resistant alloy material or coating and hardened rubber
4. Casing and Cement - N-80 and K-55 casing with portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 with good cement bond between formation and casing into the Reef Ridge Shale.

Standards

Well materials follow the following standards:

1. API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing

The Monterey Formation temperature in 26R is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. The casing will not experience loads from CO_2 injection beyond the designed capability of the well including safety factors. Subsidence has not been observed historically in the areas around the injection wells because of hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section. Casing corrosion logging data to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand CO_2 injection load cases expected with the project.

Table 1: Casing Specifications for the 373-35R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 – 54	20.000	19.124	94	--	--	2.62	--	--
Surface	14 – 331	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 – 3,006	9.625	8.835	40	K-55	Long	2.62	5,750	3,090
Long-string	14 – 79 79 – 5,028 5,028 – 6,618 6,618 – 7,988	7.000	6.276 6.366 6.276 6.276	26 23 26 26	N-80 K-55 K-55 N-80	Long	2.62	7,240 4,360 4,980 7,240	5,410 3,270 4,320 5,410

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing string was cemented with returns to surface. The 9-5/8" casing string was cemented with returns to surface. The 7" casing string was cemented in place with Class G portland cement followed with cemented to surface by annular top squeeze. Subsequently, a CBL was run from 6600' – 7900' and indicates annular isolation throughout and above the Monterey and Reef Ridge formations.

Protection of USDW

No USDW is present within the AoR. However, if USDW is discovered within the AoR in the future, the USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the potential USDW interval, providing multiple protective barriers to ensure protection of the potential USDW above the casing point.
2. The intermediate casing string is set across the base of the potential USDW, and annular cement isolates the potential USDW from the injection string by providing multiple protective barriers to ensure protection of potential USDW.
3. The cement bond log on the 7” casing string indicates annular cement within and above the injection and confining zones, providing adequate isolation of the potential USDW from CO_2 injectate.
4. SAPT tests pressure the well annulus to demonstrate isolation of primary and secondary barriers for the protection of potential USDW. All SAPT’s demonstrate that the production casing, tubing, packer, and wellhead have mechanical integrity. Casing/tubing annulus pressure tests to 500 psi for 30 minutes have been acquired through time. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	7,050	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7” casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	7,020	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7” casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with realtime injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~3,181' feet measured depth (MD) to bottom hole at 8,001 feet MD (Table 4).

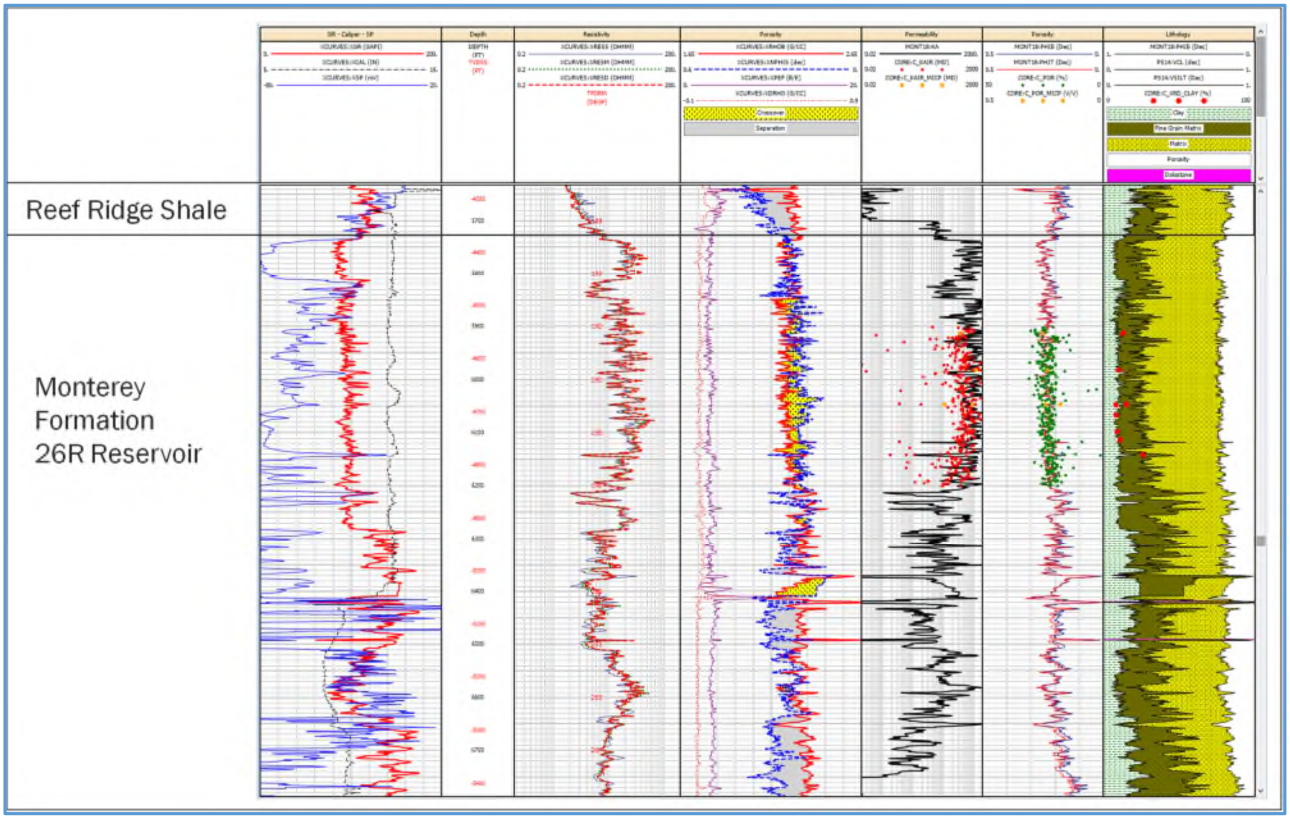
Table 4: Deviation checks during drilling for the 373-35R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
3,181.00	0.25	250.85	3,180.90		5,344.00	21.5	61.85	5,225.10
3,255.00	2	42.85	3,254.90		5,413.00	21	62.85	5,289.40
3,286.00	3.25	49.85	3,285.90		5,502.00	21.75	61.85	5,372.20
3,349.00	6	52.85	3,348.70		5,660.00	21.5	61.85	5,519.10
3,412.00	9.25	60.85	3,411.10		5,816.00	21.5	62.85	5,664.30
3,442.00	10.75	58.85	3,440.70		5,940.00	21.75	62.85	5,779.50
3,515.00	13.25	55.85	3,512.10		6,056.00	21.25	73.85	5,887.50
3,577.00	14.75	55.85	3,572.20		6,088.00	22	77.85	5,917.30
3,672.00	15.75	59.85	3,663.90		6,163.00	23.75	81.85	5,986.40
3,766.00	17.5	59.85	3,754.00		6,322.00	24	78.85	6,131.80
3,860.00	19	61.85	3,843.20		6,479.00	24	76.85	6,275.20
3,955.00	20.5	63.85	3,932.60		6,542.00	23.75	74.85	6,332.80
4,019.00	21.75	64.85	3,992.30		6,668.00	24.25	72.85	6,447.90
4,152.00	22.25	63.85	4,115.60		6,795.00	24.75	69.85	6,563.50
4,308.00	21.75	64.85	4,260.30		6,859.00	24.75	65.85	6,621.60
4,498.00	21.75	63.85	4,436.80		6,922.00	25	65.85	6,678.80
4,656.00	21.75	62.85	4,583.50		7,016.00	25.75	59.85	6,763.70
4,807.00	21.25	62.85	4,724.00		7,126.00	26.75	55.85	6,862.40
4,996.00	21	62.85	4,900.30		7,265.00	26.5	53.85	6,986.60
5,123.00	20.75	61.85	5,019.00		8,001.00	28.25	50.85	7,640.20
5,246.00	21.25	60.85	5,133.80					

Open Hole Log Analysis

Open-hole wireline log data was acquired prior to installation of 7" casing long string. Figure 1 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3, permeability in track 4, porosity in track 5, and lithology in track 6 (right most).

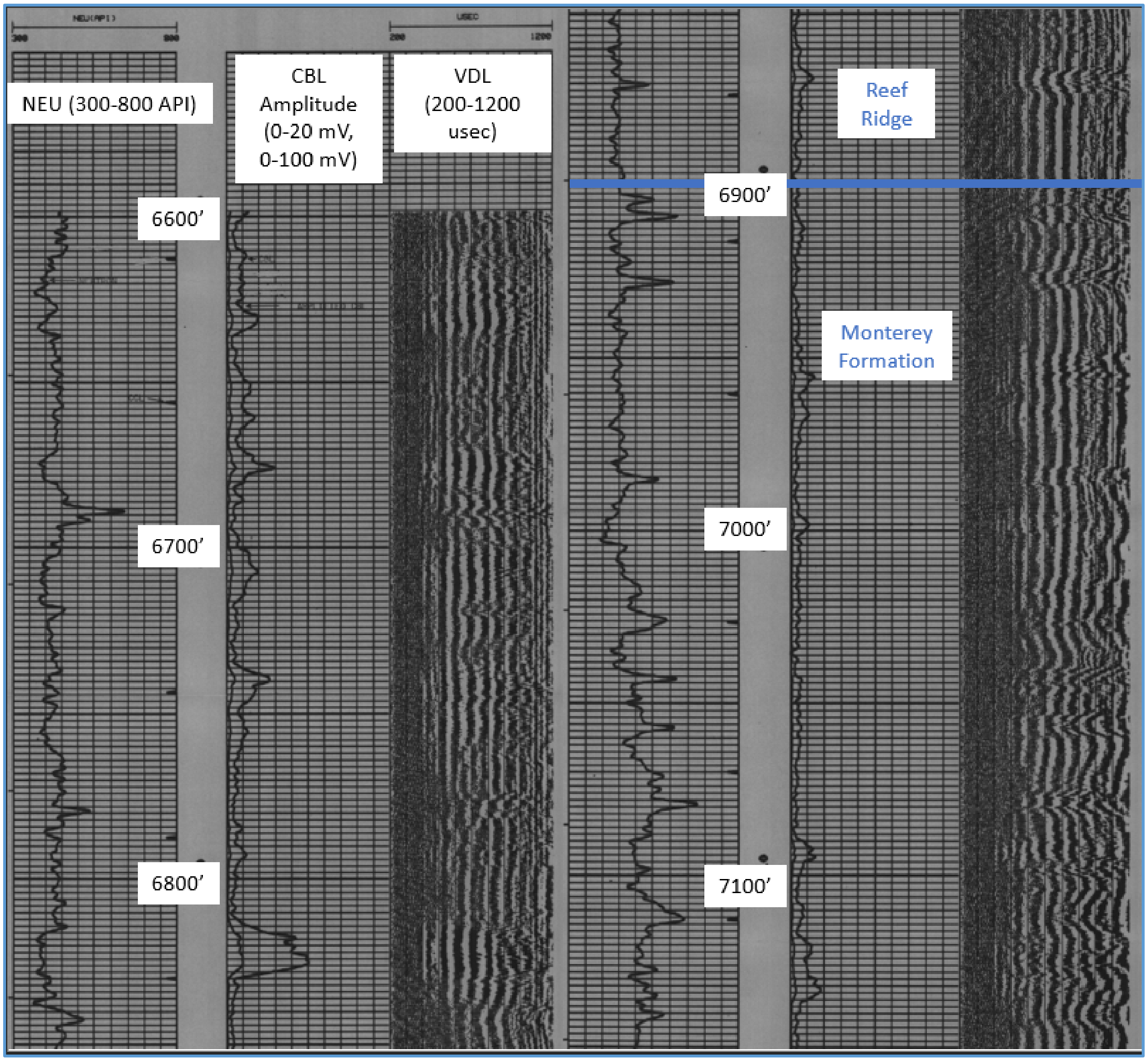
Figure 1: Open-hole well logs for 373-35R before installation of long string.



Cement Evaluation

The cement bond log amplitude and variable density log (VDL) show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 2). Late VDL arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not observed deeper than 6600', the top of the cement bond logging interval. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

Figure 2: Cement bond log example for 373-35R, after installation of long string casing. The Monterey Formation 26R top is at 6,900 feet.



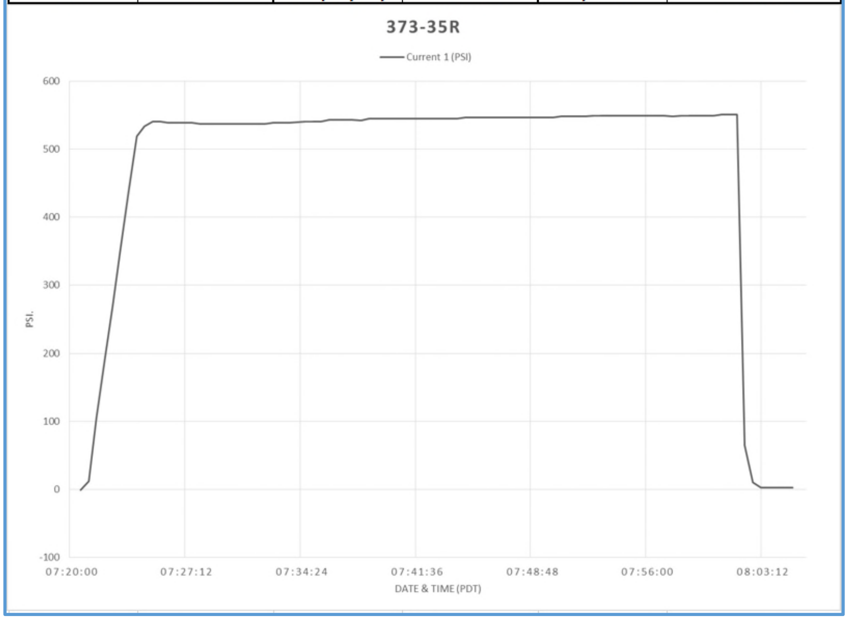
MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated August 10th, 2020, is displayed in Figure 3. It demonstrates that the annulus can hold pressure more than 500 psi without gain or loss for 30 minutes indicating mechanical integrity of the tubing, casing, and packer as the well is currently configured. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this procedure will be addressed in the Pre-Operational Testing plan document.

Figure 3: SAPT for 373-35R showing mechanical integrity of the tubing, casing, and packer.

CRC SAPT TEST

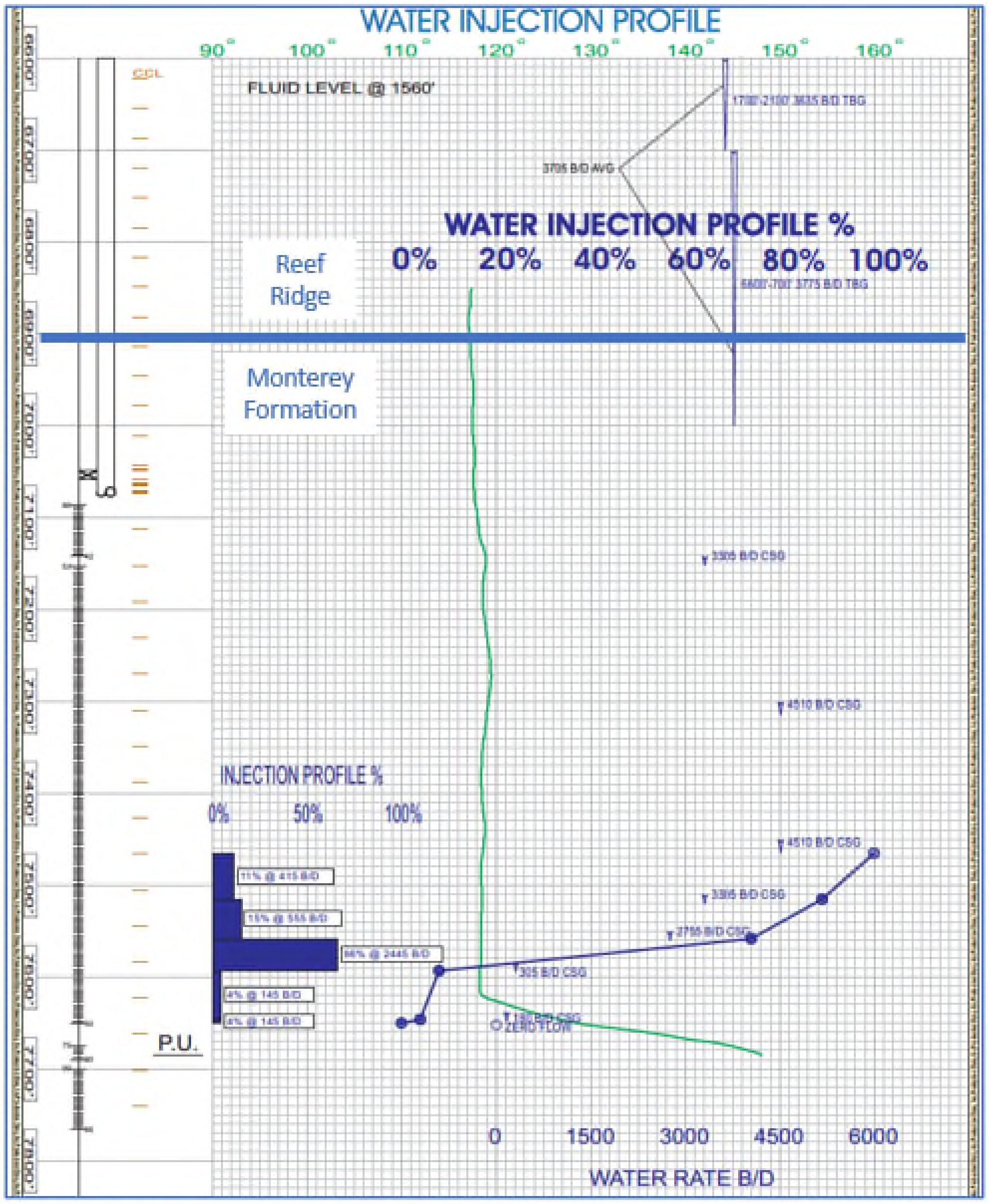
Well	373	DOGGR Rep	Christian Garcia	Date:	08/10/20
Section	35R	Witness/Waived	Waived	Time:	8:09:00 AM
API#	0402968028	Company Rep	Gabe Alanis	Operator	Benito Garcia



MIT – External: Gas Injection Survey and Temperature Log

The gas injection survey in Figure 4 was acquired on February 26th, 2020. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 7086’ or at the packer at 7050’. The analysis indicates that all injection fluid is entering perforations below ~7450’. The temperature profile in green confirms the results.

Figure 4: Radioactive tracer and temperature survey for well 373-35R showing mechanical integrity of the tubing and isolation of the perforation by the packer.



Well Operation

Operational Procedures [40 CFR 146.82(a)(10)]

Injectors will be operated to inject the desired rate of CO_2 over the life of the project.

For a target rate of 18.75 MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been calculated assuming 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection - as the 26R reservoir is depleted in pressure - a surface pressure and down hole injection pressure (calculated at top perforation) of 1014 psi and 2082 psi respectively is expected to be required to achieve the target rate. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface pressure and down hole pressures (calculated at top perforation) required are 1702 psi and 4060 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

Based on fracture stimulation data from well 388-26R in the 26R reservoir, the expected fracture gradient is 0.701 psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable downhole injection pressure is 4294 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this bottomhole pressure. 40+ years of gas and water injection experience into the Monterey Formation 26R reservoir supports that this is an appropriate and effective operating limit.

The expected pressures over the life of the project are summarized in Table 5.

Table 5: Proposed operational procedures

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Allowable Pressure	Using 0.701psi/ft fracture gradient with 10% safety factor	
Surface	1992	psig
Downhole	4294	psig
Injection Pressure @ Target rate	Expected range over project life	
Surface Start / End	1,014 /1,702	psig
Downhole Start / End	2,082 / 4,060	psig
Target Injection Rate	18.75 993	mmscfpd Tonnes/day
Annulus Pressure	Expected range over project life	
Surface Start / End	100 / 1139	psig
Downhole Start / End	3101 / 4140	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 5 are suitable to the well design and will not impact the well integrity or induce formation fracture.

Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well 373-35R, CTV expects a target injection rate of 18.75 million cubic feet per day for which the maximum expected bottom hole injection pressure is 4,060 psi. A threshold of 10% over the above injection rate and 5% above the expected bottom hole injection pressure, not to exceed maximum allowable pressure, will be used to configure automation and alarms, which equates to 20.6 million cubic feet per day and 4,263 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

Shutdown Procedures

Under routine conditions (e.g., for well workovers), CTV will reduce CO_2 injection at a rate of 165 tons per day over a 6-day period to ensure protection of health, safety, and the environment.

Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is observed or exceeded, the software will issue visual, audible, and/or digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a). A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature profile, which could be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO_2. Deviations between the temperature log performed before, during, and after injection may indicate issues related to the integrity of the well casing or cement.

Information on Plugs

CTV will use the materials and methods noted in Table 6 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend with specifications consistent with API Spec 10A will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 6, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 6: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.276	6.366	6.366	6.276
Depth to bottom of tubing or drill pipe (ft)	7,871	2,529	1,097	39
Sacks of cement to be used (each plug)	201	25	25	5
Slurry volume to be pumped (ft^3)	231	29	29	6
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6,799	2,404	972	14
Bottom of plug (ft)	7,871	2,529	1,097	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100’ inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L TDS):
    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name:	CTV I Elk Hills 26R Project 357-7R and 355-7R
Facility contact:	Travis Hurst / CCS Project Manager 28590 Highway 119 Tupman, CA 93276 (661) 342-2409 / Travis.Hurst@crc.com
Well location:	Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

CONSIDERATION OF SPECIFIC FEDERAL LAWS
40 CFR §144.4

Carbon TerraVault 1 LLC (CTV) has considered Federal Laws, including the Wild and Scenic Rivers Act (WSRA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), Coastal Zone Management Act (CZMA), and the Fish and Wildlife Conservation Act (FWCA). Description for these acts and applicability to the Elk Hills 26R storage project is described below.

Wild and Scenic Rivers Act (WSR Act)

The Wild and Scenic Rivers Act (WSR Act) of 1968 (Public Law 90-542; 16 U.S.C. 1271 *et seq*.) was enacted by Congress to preserve certain rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations. The WSR Act is notable for safeguarding the special character of these rivers, while also recognizing the potential for their appropriate use and development. It encourages river management that crosses political boundaries and promotes public participation in developing goals for river protection.

The National Wild and Scenic Rivers System (NWSRS) was created by the WSR Act and is managed by the National Park Service and the U.S. Forest Service. Rivers may be designated by Congress, or if certain requirements are met, they may be designated by the Secretary of the Interior. Designated segments need not include the entire river and may include tributaries. Each river is administered by either a federal or state agency. Section 2(b) of the WSR Act creates three classifications of protected rivers, which are defined as follows:

- "Wild River Areas" are those rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watersheds or shorelines essentially primitive and waters unpolluted. These represent vestiges of America.
- "Scenic River Areas" are those rivers or sections of rivers that are free of impoundments, with shorelines or watersheds still largely primitive and shorelines largely undeveloped, but accessible in places by roads.
- "Recreational River Areas" are those rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past.

Regardless of the classification, each river in the National System is administered with the goal of protecting and enhancing the values for which it was designated.

Based on a review of the NWSRS National Park Service (NPS) Wild and Scenic River Management GIS dataset, there are no designated wild, scenic, or recreational river areas in the

Project site. The closest designated wild, scenic, or recreational river is approximately 38 miles SW of the proposed project site (Sisquoc River) and 54 miles S of the project site (Sespe Creek).

National Historic Preservation Act (NHPA) – *National Historic Preservation Act (NHPA) §106*

In 1998, the Department of Energy (DOE) sold its interests in the former Naval Petroleum Reserve No. 1 (NPR-1) to Occidental of Elk Hills, Inc. (OEHI) – now California Resources Corporation (CRC). As part of its compliance with the National Historic Preservation Act (NHPA), DOE entered into a Programmatic Agreement (PA) with the California State Historic Preservation Officer (SHPO) and the Advisory Council of Historic Preservation (ACHP) regarding the resolution of adverse effects to historic properties from the removal of NPR-1 from federal administration by DOE. Appendix 2 to the PA is the "Cultural Resources Management Plan, Naval Petroleum Reserve No. 1, Elk Hills, Kern County, California" (CRMP), completed in 1998. That CRMP defines the measures DOE would (and did) take to implement the terms of the PA, taking into account the effects of the undertaking (i.e.,the sale of NPR-1) in accordance with Sections 106 and 110 of the NHPA. The DOE, SHPO and ACHP are signatories to the PA.

The original CRMP applied to the management and treatment of three discovery well locations, Hay Well No. 1, Hay Well No. 5 and Hay Well No. 7, in addition to eight prehistoric archaeological sites or components, CA-KER-3079/H, KER-3080, KER-3082, KER-3085, KER3168, KER-5373/H, KER-5392, and KER-5404. These sites had been determined by DOE and SHPO as National Register of Historic Places (NRHP) eligible properties. The three wells were determined NRHP-eligible per eligibility criterion (a) and all the prehistoric components of each archaeological site are considered significant per criterion (d) in 36 CFR 60.4. Management of the historic properties is carried out consistent with the original CRMP. Relative to the three wells, DOE conducted focused archival research and then produced a booklet regarding the history of the oil field. The booklet was produced and distributed per Section 2.2 of the CRMP. For the eight archaeological sites, DOE undertook and completed limited archaeological data recovery at each site. The data recovery effort was reported in Culleton et al. (2005) "Cultural Response to Environmental Change in the Buena Vista Basin: Archaeological Data Recovery at Eight Sites on the Former Naval Petroleum Reserve No. 1 (Elk Hills), Kern County, California."

Prior to the proposed CCS project undertaking, CRC will retain a qualified archaeologist to conduct an archival records search, as well as pedestrian surveys, and to initiate Native American tribal consultation as necessary. The archival records search will be conducted at the California State University, Bakersfield, Southern San Joaquin Valley Archaeological Information Center (AIC), by AIC staff to determine: (i) if prehistoric or historical archaeological sites has previously been recorded within the project study area; (ii) if the project area has been systematically surveyed by archaeologists prior to the initiation of this field study; and/or (iii) whether the region of the project is known to contain archaeological sites and to thereby be archaeologically sensitive. Additionally, a record search of the Native American Heritage Commission (NAHC) *Sacred Lands File* will be conducted to ascertain whether traditional cultural places or cultural landscapes had been identified within the proposed project site. Any historic findings will be evaluated to determine significance and a plan to avoid and mitigate any adverse impacts to archaeological resources will be prepared by the qualified archaeologist for the Project as applicable.

Endangered Species Act (ESA) – (16 U.S.C. 1531 *et seq*.), enacted in 1973, is administered by the USFWS and the National Oceanic and Atmospheric Administration Fisheries Service (formerly National Marine Fisheries Service). The purpose of the ESA is to conserve and recover endangered and threatened species, as well as the ecosystems upon which they depend. ESA requires all federal agencies to protect listed species and preserve their habitats. Section 4 of ESA sets forth a process for listing species as endangered or threatened, for designating critical habitat for listed species, and for preparing recovery plans for listed species. Section 7 requires federal agencies to consult with the USFWS or National Oceanic and Atmospheric Administration Fisheries Service to ensure their actions do not jeopardize listed species. Section 9 prohibits the "take" of a listed species. Section 10 provides a means whereby a nonfederal action with the potential to result in the incidental take of a listed species while carrying out an otherwise lawful activity may be authorized under a permit. Section 11 sets forth enforcement and penalty provisions. Under the ESA, "take" of listed wildlife species is prohibited, unless take authorization is first obtained from the USFWS. "Take" is broadly defined under the ESA and means to harass, harm, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct.

Elk Hills Oil and Gas operations have been covered under multiple Section 7 permits since 1983 (as a former DOE facility) and is currently the subject of a draft Section 10a permit. In addition, the project area is covered by a Section 2081 Incidental Take permit (ITP 2081-2014-019-04) from the California Department of Fish and Wildlife (CDFW). CRC is unique among oil companies in that we have three professional biologists on staff and a specialized environmental permit team. This group works closely with State and Federal agencies on NEPA and CEQA permitting and compliance for all our operations across the state.

As part of project planning, CRC conducted a preliminary search of the USFWS Information for Planning and Consultation (IPaC), website, a tool that streamlines the USFWS environmental review process. Based on initial review of the IPaC, no designated critical habitat is present in the project site. A total of 11 federally listed species may be present and/or adversely impacted by the proposed project. A species list obtained from the USFWS IPaC for listed species and critical habitats that may be present in or adversely affected by the proposed project is attached as reference (Figure ENV-1).

As the project planning progresses, CRC will obtain an official species list from the USFWS and resume review of the project's effects on listed species pursuant to the ESA as part of the overall regulatory review. Potential impacts on resources managed by the USFWS will be evaluated and applicable conservation measures will be designed to avoid or minimize effects to listed species, CRC will also engage with a third-party environmental consultant to assist with biological pre-activity surveys, biological assessment/report preparation, and biological and mitigation compliance monitoring as necessary.

Coastal Zone Management Act (CZMA) – As per 16 U.S.C. § 1453. Definitions

(1) The term "coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes islands, transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends inland from the shorelines only to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and to control those geographical areas which are likely to be affected by or vulnerable to sea level rise.

The closest designated coastal zone is located approximately 60 miles South of the proposed project site (Summerland) and 67 miles West of the project site (Grover Beach).

Fish and Wildlife Conservation Act (FWCA)

The Fish and Wildlife Conservation Act (FWCA) of 1980 (16 U.S.C. §§ 2901 *et seq*.) declares that fish and wildlife are of ecological, educational, esthetic, cultural, recreational, economic, and scientific value to the Nation. The Act acknowledges that historically, fish and wildlife conservation programs have focused on more recreationally and commercially important species within a particular ecosystem, without provisions for the conservation and management of nongame fish and wildlife. The purposes of this Act are to encourage all federal departments and agencies to utilize their statutory and administrative authority, to the maximum extent practicable and consistent with each agency's statutory responsibilities, and to conserve and to promote conservation of non-game fish and wildlife and their habitats. The FWCA defines "non-game fish and wildlife" as wild vertebrate animals in an unconfined state, that are not ordinarily taken for sport, fur, or food, not listed as endangered or threatened species, and not marine mammals within the context of the Marine Mammal Protection Act. Another purpose is to provide financial and technical assistance to the states for the development, revision, and implementation of conservation plans and programs for nongame fish and wildlife.

There are currently no Habitat Conservation Plans (HCP), Natural Community Conservation Plans (NCCP), or other approved conservation plans covering the proposed Project site or non-game fish and wildlife.

Figure ENV-1

IPaC resource list

This report is an automatically generated list of species and other resources such as critical habitat (collectively referred to as *trust resources*) under the U.S. Fish and Wildlife Service's (USFWS) jurisdiction that are known or expected to be on or near the project area referenced below. The list may also include trust resources that occur outside of the project area, but that could potentially be directly or indirectly affected by activities in the project area. However, determining the likelihood and extent of effects a project may have on trust resources typically requires gathering additional site-specific (e.g., vegetation/species surveys) and project-specific (e.g., magnitude and timing of proposed activities) information.

Below is a summary of the project information you provided and contact information for the USFWS office(s) with jurisdiction in the defined project area. Please read the introduction to each section that follows (Endangered Species, Migratory Birds, USFWS Facilities, and NWI Wetlands) for additional information applicable to the trust resources addressed in that section.

Location

Kern County, California

Local office

Sacramento Fish And Wildlife Office

(916) 414-6600
(916) 414-6713

Federal Building
2800 Cottage Way, Room W-2605
Sacramento, CA 95825-1846

Endangered species

This resource list is for informational purposes only and does not constitute an analysis of project level impacts.

The primary information used to generate this list is the known or expected range of each species. Additional areas of influence (AOI) for species are also considered. An AOI includes areas outside of the species range if the species could be indirectly affected by activities in that area (e.g., placing a dam upstream of a fish population even if that fish does not occur at the dam site, may indirectly impact the species by reducing or eliminating water flow downstream). Because species can move, and site conditions can change, the species on this list are not guaranteed to be found on or near the project area. To fully determine any potential effects to species, additional site-specific and project-specific information is often required.

Section 7 of the Endangered Species Act **requires** Federal agencies to "request of the Secretary information whether any species which is listed or proposed to be listed may be present in the area of such proposed action" for any project that is conducted, permitted, funded, or licensed by any Federal agency. A letter from the local office and a species list which fulfills this requirement can **only** be obtained by requesting an official species list from either the Regulatory Review section in IPaC (see directions below) or from the local field office directly.

For project evaluations that require USFWS concurrence/review, please return to the IPaC website and request an official species list by doing the following:

1. Draw the project location and click CONTINUE.
2. Click DEFINE PROJECT.
3. Log in (if directed to do so).
4. Provide a name and description for your project.
5. Click REQUEST SPECIES LIST.

Listed species[1] and their critical habitats are managed by the Ecological Services Program of the U.S. Fish and Wildlife Service (USFWS) and the fisheries division of the National Oceanic and Atmospheric Administration (NOAA Fisheries[2]).

Species and critical habitats under the sole responsibility of NOAA Fisheries are **not** shown on this list. Please contact NOAA Fisheries for species under their jurisdiction.

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1. Species listed under the Endangered Species Act are threatened or endangered; IPaC also shows species that are candidates, or proposed, for listing. See the listing status page for more information. IPaC only shows species that are regulated by USFWS (see FAQ).

2. NOAA Fisheries, also known as the National Marine Fisheries Service (NMFS), is an office of the National Oceanic and Atmospheric Administration within the Department of Commerce.

The following species are potentially affected by activities in this location:

Mammals

NAME	STATUS
Buena Vista Lake Ornate Shrew *Sorex ornatus relictus* Wherever found There is **final** critical habitat for this species. The location of the critical habitat is not available. https://ecos.fws.gov/ecp/species/1610	Endangered
Giant Kangaroo Rat *Dipodomys ingens* Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/6051	Endangered
San Joaquin Kit Fox *Vulpes macrotis mutica* Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/2873	Endangered
Tipton Kangaroo Rat *Dipodomys nitratoides nitratoides* Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/7247	Endangered

Reptiles

NAME	STATUS
Blunt-nosed Leopard Lizard *Gambelia silus* Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/625	Endangered
Giant Garter Snake *Thamnophis gigas* Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/4482	Threatened

Fishes

NAME	STATUS
Delta Smelt Hypomesus transpacificus Wherever found There is **final** critical habitat for this species. The location of the critical habitat is not available. https://ecos.fws.gov/ecp/species/321	Threatened

Insects

NAME	STATUS
Monarch Butterfly Danaus plexippus Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/9743	Candidate

Crustaceans

NAME	STATUS
Vernal Pool Fairy Shrimp Branchinecta lynchi Wherever found There is **final** critical habitat for this species. The location of the critical habitat is not available. https://ecos.fws.gov/ecp/species/498	Threatened

Flowering Plants

NAME	STATUS
Kern Mallow Eremalche kernensis Wherever found No critical habitat has been designated for this species. https://ecos.fws.gov/ecp/species/1731	Endangered

Critical habitats

Potential effects to critical habitat(s) in this location must be analyzed along with the endangered species themselves.

THERE ARE NO CRITICAL HABITATS AT THIS LOCATION.

Migratory birds

Certain birds are protected under the Migratory Bird Treaty Act[1] and the Bald and Golden Eagle Protection Act[2].

Any person or organization who plans or conducts activities that may result in impacts to migratory birds, eagles, and their habitats should follow appropriate regulations and consider implementing appropriate conservation measures, as described below.

1. The Migratory Birds Treaty Act of 1918.
2. The Bald and Golden Eagle Protection Act of 1940.

Additional information can be found using the following links:

- Birds of Conservation Concern https://www.fws.gov/program/migratory-birds/species
- Measures for avoiding and minimizing impacts to birds https://www.fws.gov/library/collections/avoiding-and-minimizing-incidental-take-migratory-birds
- Nationwide conservation measures for birds https://www.fws.gov/sites/default/files/documents/nationwide-standard-conservation-measures.pdf

The birds listed below are birds of particular concern either because they occur on the USFWS Birds of Conservation Concern (BCC) list or warrant special attention in your project location. To learn more about the levels of concern for birds on your list and how this list is generated, see the FAQ below. This is not a list of every bird you may find in this location, nor a guarantee that every bird on this list will be found in your project area. To see exact locations of where birders and the general public have sighted birds in and around your project area, visit the E-bird data mapping tool (Tip: enter your location, desired date range and a species on your list). For projects that occur off the Atlantic Coast, additional maps and models detailing the relative occurrence and abundance of bird species on your list are available. Links to additional information about Atlantic Coast birds, and other important information about your migratory bird list, including how to properly interpret and use your migratory bird report, can be found below.

For guidance on when to schedule activities or implement avoidance and minimization measures to reduce impacts to migratory birds on your list, click on the PROBABILITY OF PRESENCE SUMMARY at the top of your list to see when these birds are most likely to be present and breeding in your project area.

NAME	BREEDING SEASON (IF A BREEDING SEASON IS INDICATED FOR A BIRD ON YOUR LIST, THE BIRD MAY

BREED IN YOUR PROJECT AREA SOMETIME WITHIN THE TIMEFRAME SPECIFIED, WHICH IS A VERY LIBERAL ESTIMATE OF THE DATES INSIDE WHICH THE BIRD BREEDS ACROSS ITS ENTIRE RANGE. "BREEDS ELSEWHERE" INDICATES THAT THE BIRD DOES NOT LIKELY BREED IN YOUR PROJECT AREA.)

California Thrasher Toxostoma redivivum This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.	Breeds Jan 1 to Jul 31
Golden Eagle Aquila chrysaetos This is not a Bird of Conservation Concern (BCC) in this area, but warrants attention because of the Eagle Act or for potential susceptibilities in offshore areas from certain types of development or activities. https://ecos.fws.gov/ecp/species/1680	Breeds Jan 1 to Aug 31
Lawrence's Goldfinch Carduelis lawrencei This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. https://ecos.fws.gov/ecp/species/9464	Breeds Mar 20 to Sep 20

Probability of Presence Summary

The graphs below provide our best understanding of when birds of concern are most likely to be present in your project area. This information can be used to tailor and schedule your project activities to avoid or minimize impacts to birds. Please make sure you read and understand the FAQ "Proper Interpretation and Use of Your Migratory Bird Report" before using or attempting to interpret this report.

Probability of Presence (■)

Each green bar represents the bird's relative probability of presence in the 10km grid cell(s) your project overlaps during a particular week of the year. (A year is represented as 12 4-week months.) A taller bar indicates a higher probability of species presence. The survey effort (see below) can be used to establish a level of confidence in the presence score. One can have higher confidence in the presence score if the corresponding survey effort is also high.

How is the probability of presence score calculated? The calculation is done in three steps:

1. The probability of presence for each week is calculated as the number of survey events in the week where the species was detected divided by the total number of survey events for that week. For example, if in week 12 there were 20 survey events and the Spotted Towhee was found in 5 of them, the probability of presence of the Spotted Towhee in week 12 is 0.25.
2. To properly present the pattern of presence across the year, the relative probability of presence is calculated. This is the probability of presence divided by the maximum probability of presence across all weeks. For example, imagine the probability of presence in week 20 for the Spotted Towhee is 0.05, and that the probability of presence at week 12 (0.25) is the maximum of any week of the year. The relative probability of presence on week 12 is 0.25/0.25 = 1; at week 20 it is 0.05/0.25 = 0.2.
3. The relative probability of presence calculated in the previous step undergoes a statistical conversion so that all possible values fall between 0 and 10, inclusive. This is the probability of presence score.

To see a bar's probability of presence score, simply hover your mouse cursor over the bar.

Breeding Season (■)
Yellow bars denote a very liberal estimate of the time-frame inside which the bird breeds across its entire range. If there are no yellow bars shown for a bird, it does not breed in your project area.

Survey Effort (I)
Vertical black lines superimposed on probability of presence bars indicate the number of surveys performed for that species in the 10km grid cell(s) your project area overlaps. The number of surveys is expressed as a range, for example, 33 to 64 surveys.

To see a bar's survey effort range, simply hover your mouse cursor over the bar.

No Data (–)
A week is marked as having no data if there were no survey events for that week.

Survey Timeframe
Surveys from only the last 10 years are used in order to ensure delivery of currently relevant information. The exception to this is areas off the Atlantic coast, where bird returns are based on all years of available data, since data in these areas is currently much more sparse.

■ probability of presence ■ breeding season I survey effort – no data

SPECIES JAN FEB MAR APR MAY JUN JUL AUG SEP OCT NOV DEC

California Thrasher
BCC Rangewide (CON) (This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.)

Golden Eagle
Non-BCC Vulnerable (This is not a Bird of Conservation Concern (BCC) in this area, but warrants attention because of the Eagle Act or for potential susceptibilities in offshore areas from certain types of development or activities.)

Lawrence's Goldfinch
BCC Rangewide (CON) (This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.)

Tell me more about conservation measures I can implement to avoid or minimize impacts to migratory birds.

Nationwide Conservation Measures describes measures that can help avoid and minimize impacts to all birds at any location year round. Implementation of these measures is particularly important when birds are most likely to occur in the project area. When birds may be breeding in the area, identifying the locations of any active nests and avoiding their destruction is a very helpful impact minimization measure.

To see when birds are most likely to occur and be breeding in your project area, view the Probability of Presence Summary. Additional measures or permits may be advisable depending on the type of activity you are conducting and the type of infrastructure or bird species present on your project site.

What does IPaC use to generate the migratory birds potentially occurring in my specified location?

The Migratory Bird Resource List is comprised of USFWS Birds of Conservation Concern (BCC) and other species that may warrant special attention in your project location.

The migratory bird list generated for your project is derived from data provided by the Avian Knowledge Network (AKN). The AKN data is based on a growing collection of survey, banding, and citizen science datasets and is queried and filtered to return a list of those birds reported as occurring in the 10km grid cell(s) which your project intersects, and that have been identified as warranting special attention because they are a BCC species in that area, an eagle (Eagle Act requirements may apply), or a species that has a particular vulnerability to offshore activities or development.

Again, the Migratory Bird Resource list includes only a subset of birds that may occur in your project area. It is not representative of all birds that may occur in your project area. To get a list of all birds potentially present in your project area, please visit the AKN Phenology Tool.

What does IPaC use to generate the probability of presence graphs for the migratory birds potentially occurring in my specified location?

The probability of presence graphs associated with your migratory bird list are based on data provided by the Avian Knowledge Network (AKN). This data is derived from a growing collection of survey, banding, and citizen science datasets .

Probability of presence data is continuously being updated as new and better information becomes available. To learn more about how the probability of presence graphs are produced and how to interpret them, go the Probability of Presence Summary and then click on the "Tell me about these graphs" link.

How do I know if a bird is breeding, wintering, migrating or present year-round in my project area?

To see what part of a particular bird's range your project area falls within (i.e. breeding, wintering, migrating or year-round), you may refer to the following resources: The Cornell Lab of Ornithology All About Birds Bird Guide, or (if you are unsuccessful in locating the bird of interest there), the Cornell Lab of Ornithology Neotropical Birds guide. If a bird on your migratory bird species list has a breeding season associated with it, if that bird does occur in your project area, there may be nests present at some point within the timeframe specified. If "Breeds elsewhere" is indicated, then the bird likely does not breed in your project area.

What are the levels of concern for migratory birds?

Migratory birds delivered through IPaC fall into the following distinct categories of concern:

1. "BCC Rangewide" birds are Birds of Conservation Concern (BCC) that are of concern throughout their range anywhere within the USA (including Hawaii, the Pacific Islands, Puerto Rico, and the Virgin Islands);
2. "BCC - BCR" birds are BCCs that are of concern only in particular Bird Conservation Regions (BCRs) in the continental USA; and

3. "Non-BCC - Vulnerable" birds are not BCC species in your project area, but appear on your list either because of the Eagle Act requirements (for eagles) or (for non-eagles) potential susceptibilities in offshore areas from certain types of development or activities (e.g. offshore energy development or longline fishing).

Although it is important to try to avoid and minimize impacts to all birds, efforts should be made, in particular, to avoid and minimize impacts to the birds on this list, especially eagles and BCC species of rangewide concern. For more information on conservation measures you can implement to help avoid and minimize migratory bird impacts and requirements for eagles, please see the FAQs for these topics.

Details about birds that are potentially affected by offshore projects

For additional details about the relative occurrence and abundance of both individual bird species and groups of bird species within your project area off the Atlantic Coast, please visit the Northeast Ocean Data Portal. The Portal also offers data and information about other taxa besides birds that may be helpful to you in your project review. Alternately, you may download the bird model results files underlying the portal maps through the NOAA NCCOS Integrative Statistical Modeling and Predictive Mapping of Marine Bird Distributions and Abundance on the Atlantic Outer Continental Shelf project webpage.

Bird tracking data can also provide additional details about occurrence and habitat use throughout the year, including migration. Models relying on survey data may not include this information. For additional information on marine bird tracking data, see the Diving Bird Study and the nanotag studies or contact Caleb Spiegel or Pam Loring.

What if I have eagles on my list?

If your project has the potential to disturb or kill eagles, you may need to obtain a permit to avoid violating the Eagle Act should such impacts occur.

Proper Interpretation and Use of Your Migratory Bird Report

The migratory bird list generated is not a list of all birds in your project area, only a subset of birds of priority concern. To learn more about how your list is generated, and see options for identifying what other birds may be in your project area, please see the FAQ "What does IPaC use to generate the migratory birds potentially occurring in my specified location". Please be aware this report provides the "probability of presence" of birds within the 10 km grid cell(s) that overlap your project; not your exact project footprint. On the graphs provided, please also look carefully at the survey effort (indicated by the black vertical bar) and for the existence of the "no data" indicator (a red horizontal bar). A high survey effort is the key component. If the survey effort is high, then the probability of presence score can be viewed as more dependable. In contrast, a low survey effort bar or no data bar means a lack of data and, therefore, a lack of certainty about presence of the species. This list is not perfect; it is simply a starting point for identifying what birds of concern have the potential to be in your project area, when they might be there, and if they might be breeding (which means nests might be present). The list helps you know what to look for to confirm presence, and helps guide you in knowing when to implement conservation measures to avoid or minimize potential impacts from your project activities, should presence be confirmed. To learn more about conservation measures, visit the FAQ "Tell me about conservation measures I can implement to avoid or minimize impacts to migratory birds" at the bottom of your migratory bird trust resources page.

Coastal Barrier Resources System

Projects within the John H. Chafee Coastal Barrier Resources System (CBRS) may be subject to the restrictions on federal expenditures and financial assistance and the consultation requirements of the Coastal Barrier Resources Act (CBRA) (16 U.S.C. 3501 et seq.). For more information, please contact the local Ecological Services Field Office or visit the CBRA Consultations website. The CBRA website provides tools such as a flow chart to help determine whether consultation is required and a template to facilitate the consultation process.

THERE ARE NO KNOWN COASTAL BARRIERS AT THIS LOCATION.

Data limitations

The CBRS boundaries used in IPaC are representations of the controlling boundaries, which are depicted on the official CBRS maps. The boundaries depicted in this layer are not to be considered authoritative for in/out determinations close to a CBRS boundary (i.e., within the "CBRS Buffer Zone" that appears as a hatched area on either side of the boundary). For projects that are very close to a CBRS boundary but do not clearly intersect a unit, you may contact the Service for an official determination by following the instructions here: https://www.fws.gov/service/coastal-barrier-resources-system-property-documentation

Data exclusions

CBRS units extend seaward out to either the 20- or 30-foot bathymetric contour (depending on the location of the unit). The true seaward extent of the units is not shown in the CBRS data, therefore projects in the offshore areas of units (e.g., dredging, breakwaters, offshore wind energy or oil and gas projects) may be subject to CBRA even if they do not intersect the CBRS data. For additional information, please contact CBRA@fws.gov.

Facilities

National Wildlife Refuge lands

Any activity proposed on lands managed by the National Wildlife Refuge system must undergo a 'Compatibility Determination' conducted by the Refuge. Please contact the individual Refuges to discuss any questions or concerns.

THERE ARE NO REFUGE LANDS AT THIS LOCATION.

Fish hatcheries

THERE ARE NO FISH HATCHERIES AT THIS LOCATION.

Wetlands in the National Wetlands Inventory

Impacts to NWI wetlands and other aquatic habitats may be subject to regulation under Section 404 of the Clean Water Act, or other State/Federal statutes.

For more information please contact the Regulatory Program of the local U.S. Army Corps of Engineers District.

WETLAND INFORMATION IS NOT AVAILABLE AT THIS TIME

This can happen when the National Wetlands Inventory (NWI) map service is unavailable, or for very large projects that intersect many wetland areas. Try again, or visit the NWI map to view wetlands at this location.

Data limitations

The Service's objective of mapping wetlands and deepwater habitats is to produce reconnaissance level information on the location, type and size of these resources. The maps are prepared from the analysis of high altitude imagery. Wetlands are identified based on vegetation, visible hydrology and geography. A margin of error is inherent in the use of imagery; thus, detailed on-the-ground inspection of any particular site may result in revision of the wetland boundaries or classification established through image analysis.

The accuracy of image interpretation depends on the quality of the imagery, the experience of the image analysts, the amount and quality of the collateral data and the amount of ground truth verification work conducted. Metadata should be consulted to determine the date of the source imagery used and any mapping problems.

Wetlands or other mapped features may have changed since the date of the imagery or field work. There may be occasional differences in polygon boundaries or classifications between the information depicted on the map and the actual conditions on site.

Data exclusions

Certain wetland habitats are excluded from the National mapping program because of the limitations of aerial imagery as the primary data source used to detect wetlands. These habitats include seagrasses or submerged aquatic vegetation that are found in the intertidal and subtidal zones of estuaries and nearshore coastal waters. Some deepwater reef communities (coral or tuberficid worm reefs) have also been excluded from the inventory. These habitats, because of their depth, go undetected by aerial imagery.

Data precautions

Federal, state, and local regulatory agencies with jurisdiction over wetlands may define and describe wetlands in a different manner than that used in this inventory. There is no attempt, in either the design or products of this inventory, to define the limits of proprietary jurisdiction of any Federal, state, or local government or to establish the geographical scope of the regulatory programs of government agencies. Persons intending to engage in activities involving modifications within or adjacent to wetland areas should seek the advice of appropriate federal, state, or local agencies concerning specified agency regulatory programs and proprietary jurisdictions that may affect such activities.

Class VI Injection Well: Quality Assurance and Surveillance Plan

Update May 31, 2022

Prepared by:

Carbon TerraVault 1 LLC

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Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills 26R Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst

May 31, 2022

Signature Date

Travis Hurst

Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Travis Hurst: CCS Project Manager

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

A. Project Management

A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill 26R Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

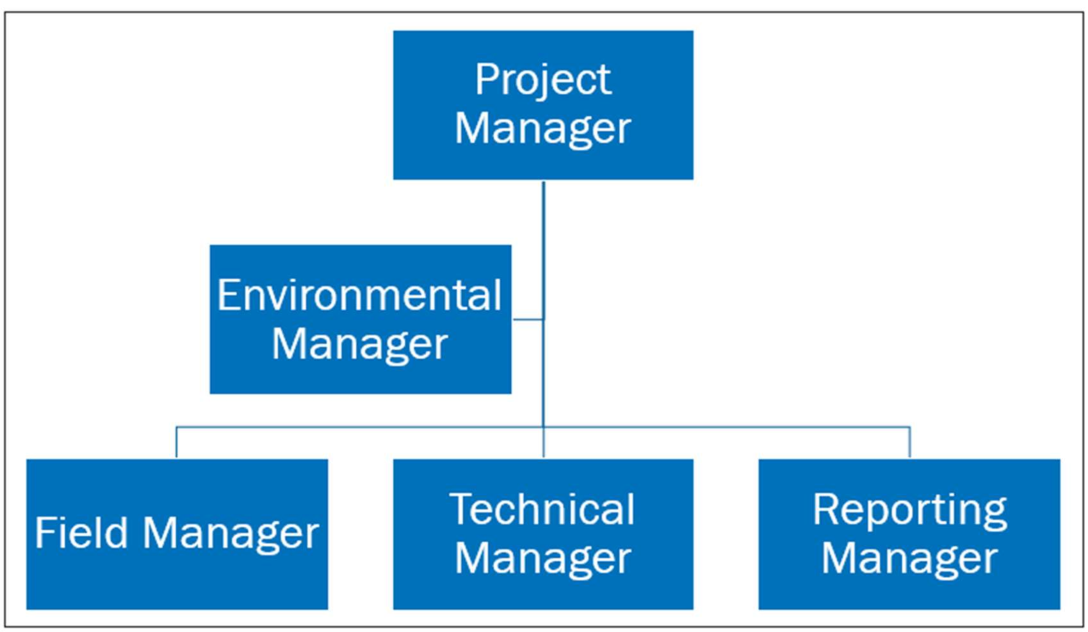
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills 26R project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Figure 1: Organizational Chart.



A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills 26R project will inject and sequester CO_2 from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO_2 injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO_2 injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the CO_2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor Injectate
Injection rate and volume	Injection Well	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection wellhead	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Temperature	Along Wellbore	DTS	Direct Measurement	NA	Monitor temperature
Downhole pressure/ temperature	Injection Well	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Zalco Labs	Monitor corrosion of materials
Mechanical integrity	Injection Well	Temperature		NA	Wellbore Integrity
Pressure Fall Off Test	Injection Well	Pressure gauge	Pressure Transient Analysis	NA	Reservoir Assessment

Table 2. Monitoring Well Summary

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Monitoring Wells Above Confining Layer					
Fluid Sampling Tulare Formation (USDW)	USDW Monitoring Well	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pressure/Temperature Tulare Formation (USDW)	USDW Monitoring Well	Gauge	Direct Measurement	NA	Monitor pressure / temperature
Pressure/Temperature Etchegoin Formation	355X-26R	Gauge	Direct Measurement	NA	Monitor pressure/Temperature
Temperature Etchegoin Formation	355X-26R	DTS	Direct Measurement	NA	Monitor Temperature
Fluid Sampling Etchegoin Formation	355X-26R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Monterey Formation 26R Reservoir					

Pressure/Temperature	328-25R, 376-36R, 341-27R	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure/temperature
Temperature	328-25R, 376-36R, 341-27R	DTS	Direct Measurement	NA	Temperature
Fluid Sampling	328-25R, 376-36R, 341-27R	Direct Sampling	Chemical Analysis	Zalco Labs	Monitor water quality
Pulse Neutron Log	328-25R, 376-36R, 341-27R	Logging	Logging	NA	Saturation

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for the Elk Hills 26R storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare, Etchegoin and Monterey Formation water.

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, SB, Se, Zn, Ti)	ICP-MS EPA Method 6020	0.05 to 5 mg/L	**15%**	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B	0.1 to 2 mg/L	**15%**	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	0.02-0.13 mg/L	**15%**	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO_2	Coulometric titration ASTM D513-11	10 mg/L	**NA**	Duplicate analysis
Total dissolved solids	Gravimetry; Method 2540 C	10 mg/L	**10%**	Daily balance calibration, duplicates, blanks
Alkalinity	Method 2320B	10 mg/L	10%	Duplicate analysis
pH (field)	EPA 150.1	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance (field)	SM 2510 B	10 ohms/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
δ13C	Isotope ratio mass spectrometry	12.2 mg/L HCO_3	0.15%	Duplicate analysis
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	1 mg/L	5-10% of reading	Daily calibration, duplicates

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO_2 Stream.

Parameters	Analytical Methods[1]	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ISBT 10.0 THA (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ISBT 10.1 (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ISBT 14.0 (GC/SCD)	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	ISBT 11.0 (GC/FID)	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO_2 purity	ISBT 2.0	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ISBT 14.0 (GC/SCD)	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	Duplicate analysis

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (Tulare USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO_2 will decrease the water pH.
Above-confining-zone pressure (Etchegoin)	Action will be taken if the pressure of the Etchegoin Formation pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.04365 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 – 3,000 PSI and 4-20 mA
Initial pressure accuracy	<0.03125%
Pressure resolution	0.001 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.025 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

Table 14. Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	0 to 3,000 PSI
Initial mass flow rate accuracy	0.1 % of upper range limit
Mass flow rate resolution	0.1 PSI
Mass flow rate drift stability	Estimate <0.3% of output reading for 12 months

A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design

B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

A shallow groundwater monitoring well will assess potential changes in the Upper Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. The zone is unsaturated and does not have a water level. The shallow monitoring well location was selected for the following reasons:

1. It is within the AoR.
2. The well will be completed across the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the 26R Storage project and fluid analysis.

Deep Groundwater Monitoring Strategy

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation sand (4,062 feet measured depth) will be pressure monitored for potential CO_2 leakage via the 355X-26R well. The sands have adequate continuity, porosity, and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the 26R reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

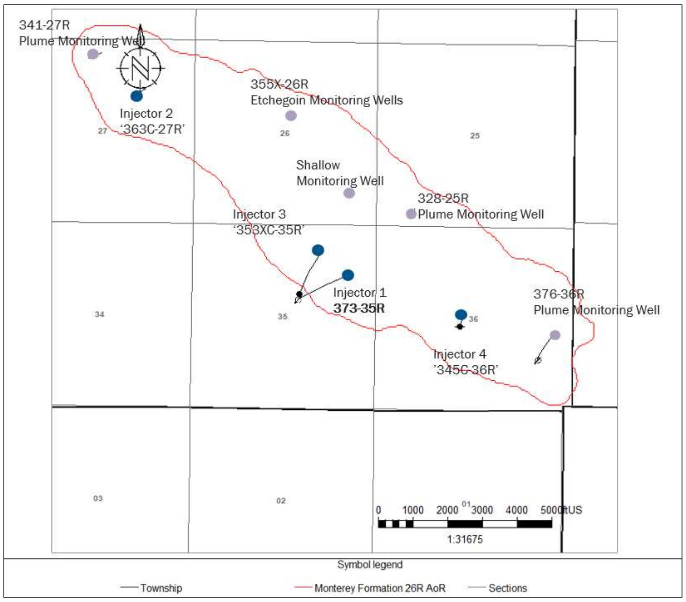
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

Figure 2: Monitoring well locations.



B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.

Field Parameter	Stabilization Criteria
pH	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.
2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, K, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti	100 mL plastic	Nitric acid	180 days
Anions: Br, Cl, F, NO_3 and SO_4	100 mL plastic	None	48 hours
Dissolved CO_2	100 ml plastic	None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	None	14 days
Alkalinity	100 mL plastic	None	14 days

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the 26R Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the 26R Storage project are industry standard and well defined. Method performance criteria is not necessary.

B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic events are discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the 26R Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the 26R Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

D. Data Validation and Usability

D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

References

ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of groundwater samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), Standard guide for field filtration of ground-water samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

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U.S. Environmental Protection Agency (USEPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

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U.S. Environmental Protection Agency (EPA). 1993. Subsurface Characterization and Monitoring Techniques; A Desk Reference Guide. Volume 1: Solids and Ground Water. U.S. Environmental Protection Agency, Washington, D.C. EPA/625/R-93/003a.

Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

Wireline Log Quality Control Reference Manual

Schlumberger

RST and RSTPro

Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

Specifications

Measurement Specifications

	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed†	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation‡	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

† See Tool Planner application for advice on logging speed.
‡ Depth of investigation is formation and environment dependent.

Mechanical Specifications

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	1 13/16 in [4.60 cm] With flask: 2 1/4 in [5.72 cm]	2 7/8 in [7.30 cm]
Borehole size—max.	9 5/8 in [24.45 cm] With flask: 9 5/8 in [24.45 cm]	9 5/8 in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

Tool quality control

Standard curves

The RST and RSTPro standard curves are listed in Table 1.

Table 1. RST and RSTPro Standard Curves

Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/oxygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM_SIG	Formation sigma uncertainty
TRAT_FIL	RST near/far capture ratio

Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

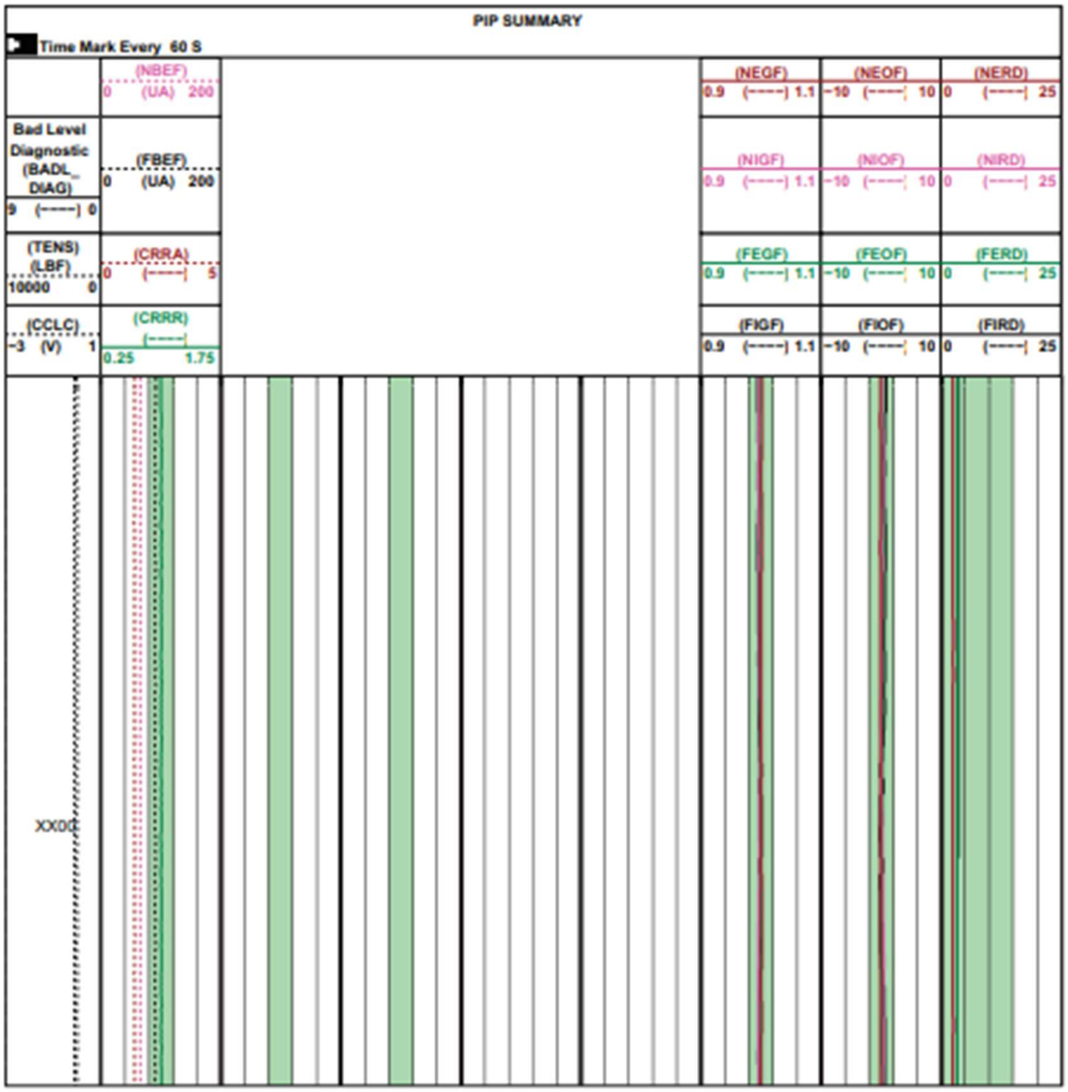

Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

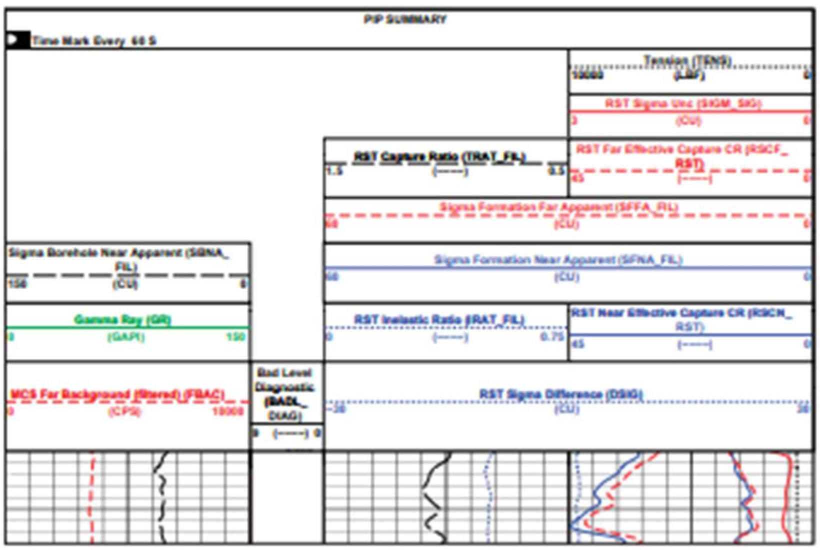

Figure 2. RST and RSTPro sigma standard format.

Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contributing Materials to RST and RSTPro Yields

Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RSTPro Capture and Sigma Modes

Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

Schlumberger

Cement Bond Tool

Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

Specifications

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h]†
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None

† Speed can be reduced depending on data quality.

Measurement Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	3.375 in [8.57cm]
Borehole size—max.	13.375 in [33.97 cm]
Outside diameter	2.75 in [6.985 cm]
Weight	309 lbm [140 kg]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBT standard curves are listed in Table 1.

Table 1. CBT Standard Curves

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-*t*)
DTMD	Delta-*t* mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation†
SB1	Short bond index†
SCBL	Short synthetic CBL†
TT1	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

† In fast formations only

Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

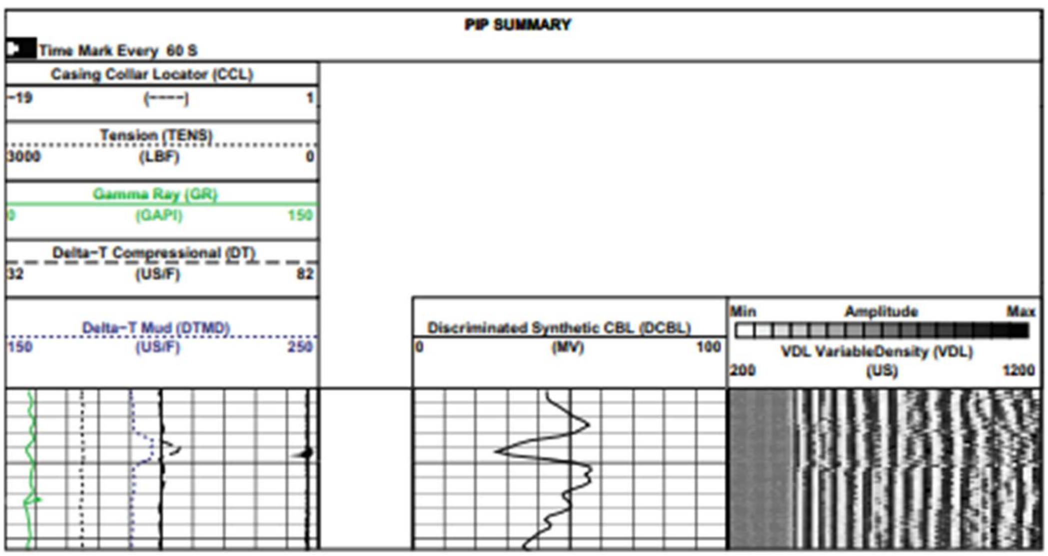

Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

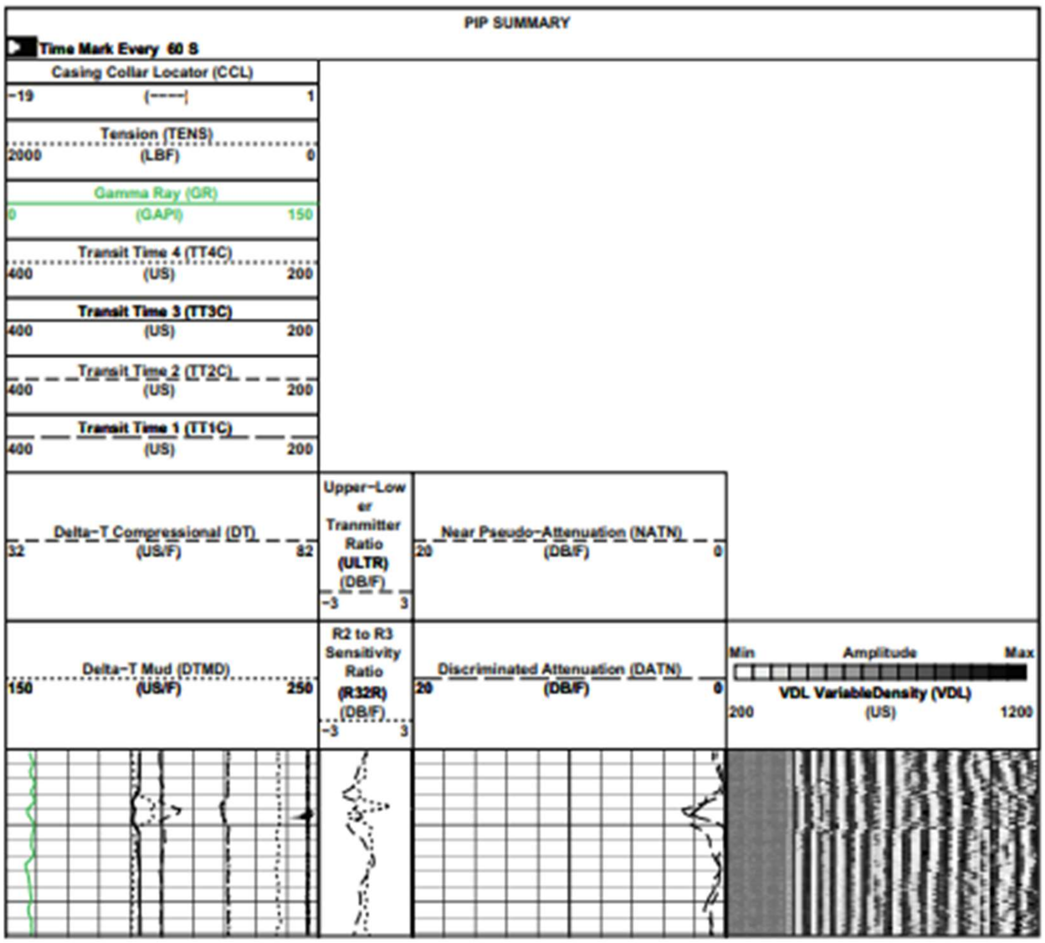

Figure 2. Additional CBT standard format for CBL and VDL.

Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions

Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40[†]	52 ± 5	329	272	NM[‡]

[†] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[‡] NM = not meaningful

Schlumberger

Cement Bond Logging

Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

Specifications

Measurement Specifications

	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	**Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)**
Output	SLS-C, SLS-D, SLS-W, and SLS-E.[†] 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms
Logging speed	3,600 ft/h [1,097 m/h]	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]
Vertical resolution	Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]
Depth of investigation	Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties	DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties
Mud type or weight limitations	None	None
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations

[†] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

Mechanical Specifications				
	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID—min.	5 in [12.70 cm]	5 in [12.70 cm]	3½ in [8.89 cm]	4 in [10.16 cm]
Casing ID—max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3⅝ in [9.21 cm]	3¾ in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers: 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers: 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 lbf [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf [19,570 N]

Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

Tool quality control

Standard curves

CBL standard curves are listed in Table 1.

Table 1. CBL Standard Curves

Output Mnemonic	Output Name
BI	Bond index
CBL	Cement bond log (fixed gate)
CBLF	Fluid-compensated cement bond log
CBSL	Cement bond log (sliding gate)
CCL	Casing collar log
GR	Gamma ray
TT	Transit time (fixed gate)
TTSL	Transit time (sliding gate)
VDL	Variable Density log

Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

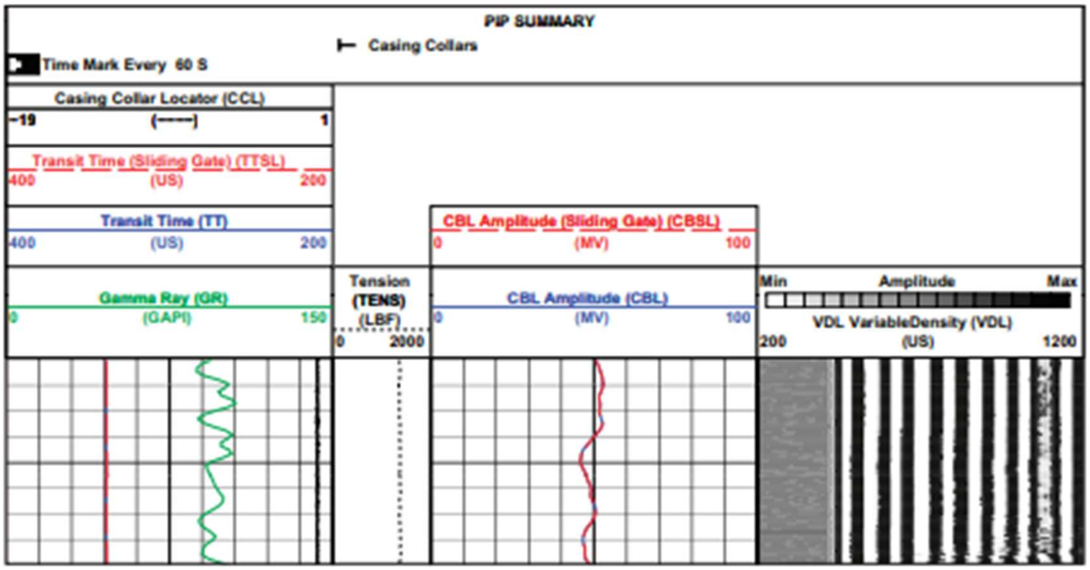

Figure 1. DSLT standard format.

Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions

Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV
5	13	4.494	77 ± 8
5.5	17	4.892	71 ± 7
7	23	6.366	62 ± 6
8.625	36	7.825	55 ± 6
9.625	47	8.681	52 ± 5
10.75	51	9.850	49 ± 5
13.375	61	12.515	43 ± 4
18.625	87.5	17.755	35 ± 4